BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2019-185-E

IN RE: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 5841-20(A)	)))))))))))	**AMENDED DIRECT TESTIMONY OF ED BURGESS ON BEHALF OF SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

*Confidential Information has been redacted. A non-redacted copy is being filed under seal.

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I. TESTIMONY SUMMARY

Q. Can you please provide a brief overview of your testimony?

A. Yes. My testimony can be summarized as follows.

First, I provide background information on:

- The underlying utility incentive structures that may influence Duke's proposed avoided cost rates in this proceeding, and
- The potential costs and risks to Duke's customers from traditional resources versus QF resources.

Second, I provide an analysis and critique of issues related to Duke's proposed avoided energy cost rates, including:

- The prevalence of negative avoided cost values that may reflect unrealistic modeling inputs and depress avoided cost rates;
- The treatment of DEP East and DEP West as a single area, which may depress avoided cost rates for DEP in South Carolina;
- The selection of pricing periods that undervalues avoided costs from solar QFs.

Third, I provide an analysis and critique of Duke's proposed avoided capacity cost rates including:

- Duke's approach to the seasonal allocation of capacity value, which strongly disfavor solar QFs;
- Duke's peaker capital cost assumptions, which depress overall avoided cost rates;

- Duke's treatment of near-term capacity value for DEC, which also reduces avoided cost rates.

Fourth, I provide an analysis and critique of Duke's proposed integration charge including:

- Statutory guidelines under Act 62 for completing an independent integration study;
- Deficiencies in Duke's modeling approach that do not match real-world operations;
- Background on integration costs more broadly.

Finally, I present alternative approaches for calculating the avoided cost rates for energy and capacity that correct for the deficiencies described above. Additionally, I recommend that the Commission reject Duke's proposed integration charge until the independent study authorized by Act 62 is completed. In the event that a future integration charge is adopted, I provide a framework for how such a charge could be determined.

II. <u>INTRODUCTION</u>

Q. Please state your name, occupation, and business address.

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please summarize your professional and educational background.

A. Currently, I am a leader on Strategen's consulting team and oversee much of the firm's work with its governmental clients, non-governmental organizations and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have managed or supported projects for numerous client engagements related to policies, programs and rate designs for distributed energy resources, including renewable energy, electric vehicles, energy storage, and demand-side management. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and appeared before the Corporation Commission on a variety of solar-related issues. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Art degree in Chemistry from Princeton University. A full resume is attached in Exhibit Burgess-1.

Q. Please further detail your experience with avoided costs and related issues.

A. I have been involved with numerous state regulatory proceedings related to compensation for distributed resources including avoided cost, cost effectiveness, net energy metering and value of solar. This includes proceedings in states such as New Hampshire, New York, Arizona, California, and Massachusetts. My clients have ranged from consumer advocates, non-governmental organizations, solar energy trade associations, and project developers. My role in these proceedings has ranged from conducting technical and economic analyses, drafting testimony and public comments, providing strategic guidance, participating in technical sessions and working groups, and appearing as an expert witness at evidentiary hearings.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the South Carolina Solar Business Alliance ("SBA"). Members of SBA include Independent Power Producers that sell the output of their facilities to incumbent utilities like Duke Energy pursuant to the Public Utility Regulatory Policies Act, 18 U.S.C. Sec. 824a-3, *et seq.* ("PURPA"). Strategen was selected to support the SBA in this proceeding of the South Carolina Public Service Commission ("PSC").

Q. What is the purpose of your testimony?

A. My testimony will address the avoided cost rates proposed by Duke Energy for both Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). I will provide a critique of the methodological choices used by Duke to calculate avoided costs and present several recommendations. I will also present an alternative calculation of avoided cost for the Commission's consideration.

Q. Have you ever testified before this Commission?

A. No.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I testified on behalf of the Massachusetts Attorney General's Office (AGO) at the evidentiary hearings for D.P.U. 18-150 (general rate case for National Grid) and for D.P.U. 17-140, which was directly related to compensation for distributed solar generation. I have also supported the AGO as a technical consultant in other recent cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and D.P.U. 17-146. Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at state Public Utilities Commissions including Arizona, New Hampshire, Nevada, Oregon, Pennsylvania, North Carolina, Maryland, District of Columbia, New York, Minnesota, Ohio, at the Federal Energy Regulatory Commission, and at the California Independent System Operator ("ISO").

Q. How is your testimony organized?

A. My testimony is presented in seven sections. Section I is a summary of my observations and recommendations. Section II is this introduction. Section III describes the inherent bias utilities like Duke have to establish low avoided cost rates for QFs. Section IV discusses how QFs help to contain costs and reduce risk for customers. Section V provides my assessment of the Company's approach to determining avoided energy cost rates and recommends an alternative. Section VI addresses my assessment of the Company's approach to avoided capacity cost rates and recommends an alternative. Finally, Section VII provides my assessment of the Company's method for calculating variable integration costs and recommends an alternative approach.

III. <u>UTILITY BIAS TOWARD LOW QF RATES</u>

Q. What considerations should be taken into account regarding utility incentives before discussing Duke's avoided cost calculations?

A. The calculation of avoided costs is generally portrayed as a precise and scientific exercise. However, it is important to recognize that some level of uncertainty is inherent and unavoidable in most aspects of the electric power system, including the models and forward-looking projections used to calculate avoided costs. In addition, the person(s) calculating avoided costs must make a number of subjective choices about the model inputs, assumptions, and methodologies. Each of these choices may influence the outcome one way or another. Since the initial starting point of this proceeding is the utility's proposal, it is useful to understand what underlying financial incentives utilities have to make those choices in a way that tends to result in lower avoided cost calculations, and whether there is cause for the utility to submit a proposal that contains certain biases.

Q. What incentives related to avoided cost rates should decision-makers consider when evaluating Duke's proposal?

A. As a publicy traded company Duke Energy has an obligation to maximize returns for its shareholders. Duke's profit maximizing responsibility gives it at least two important incentives regarding avoided cost rates. The first is that Duke, like other vertically integrated utilities, can maximize profits for shareholders by building and owning its own sources of generation. The second is that Duke's business model incentivizes the company to maintain or increase natural gas consumption in the region.

Q. Why is Duke incentivized to own its own sources of generation, even if this is economically inefficient from a system perspective?

A. Because regulated utility companies earn an authorized rate of return on invested capital in rate base, they can increase total shareholder earnings by making new capital investments[1]. Thus, it is logical for Duke to pursue sole ownership of generation assets, rather than enable competitive generators such as QFs to crowd out potential utility owned assets. This is because these competitors could obviate the need for utility-owned generation, thereby reducing future investment opportunities for Duke's shareholders.

Q. How could this bias towards utility capital expenditures affect the utility's avoided cost proposal in this proceeding?

A. In order to exclude potential competitive generators and maintain its ownership of generation resources, Duke has an incentive to propose artificially low avoided cost rates and impose other barriers to competitive generators, such as the integration services charge.

[1] This is also commonly known as the Averch-Johnson Effect, https://en.wikipedia.org/wiki/Averch%E2%80%93Johnson_effect

Q. Why is Duke incentivized to maximize natural gas utilization in its service territory?

A. Duke is affiliated with other subsidiaries under its holding company that own and operate natural gas transmission and distribution pipelines in the region.[2] In addition, Duke provides retail gas service in the Carolinas through its Piedmont affiliate. Thus, Duke has a vested interest in increasing the overall throughput of natural gas both in terms of wholesale sales, retail sales, and pipeline expansion opportunities.

Q. How does this natural gas bias affect the utility's avoided cost proposal in this proceeding?

A. Natural gas is a major fuel source for electric power output from plants in the Carolinas that may be offset by solar QFs. Therefore, the more QFs participating under avoided cost rates, the less natural gas throughput there may be through Duke-affiliated pipelines. This contradicts the economic incentives of the broader Duke holding companies. Thus, Duke has an incentive to propose artificially low avoided cost rates and impose other barriers to competitive generators, such as the solar integration charge.

[2] For example, see Duke's recent Annual Report at page 15, https://www.duke-energy.com/_/media/pdfs/our-company/investors/de-annual-reports/2018/2018-duke-energy-annual-report.pdf?la=en

Q. Is Duke's proposed Avoided Cost methodology and resulting rates biased towards lower QF rates for solar?

A. Yes. While there is no single overriding factor that causes QF rates to be lower, Duke has made many small but meaningful methodological choices that each drive rates down incrementally. These smaller factors combine to create a resulting QF rate that is, in the aggregate, significantly biased against solar QFs.

Q. Can you provide a list of these individual factors that appear to be biased against solar QFs?

A. Yes. The factors include the following:

- Selection of the time periods used to calculate the avoided energy cost rates.
- Use of a model (and associated inputs) that results in a significant number of projected hours where the avoided cost is negative, thereby leading to lower final avoided cost rates.
- Averaging of avoided energy costs between the DEP East and DEP West areas which have very different marginal resource costs.

- Selection of very low capital costs for a new peaker plant that are in turn used to calculate avoided capacity cost rates.
- Assumption that the avoided capacity value for DEC is zero for several years.
- Seasonal allocation of capacity value that is weighted towards non-solar hours (based on a study with potentially biased inputs).
- Inclusion of an Integration Service Charge based on a study with flawed input assumptions.

IV. **<u>IMPACT OF QF RATES ON UTILITY CUSTOMERS</u>**

Q. Please describe how QF rates impact the electric utility's revenue requirement recovered from consumers.

A. The rates paid out to QF resources are included in the electric utility's revenue requirement recovered from customers. The increased revenue requirement due to additional QF resources on the utility's system should in theory avoid a cost the utility would have incurred on a one-to-one basis. However, accurately reflecting the actual costs that QF resources avoid is a task subject to significant uncertainty. Thus, it is useful to consider setting QF rates that are within a "zone of reasonableness." The "zone of reasonableness" refers to the range of possible QF rates derived from inherently uncertain inputs and methods used to estimate the utility's actual future avoided costs. An example of an inherently uncertain input used to estimate avoided costs is the projections of fuel costs (e.g. $/MMBtu of natural gas) of the utility's resources.

Q. For the benefit of electric consumers, where within the "zone of reasonableness" should QF rates be set?

A. Rates for QF resources, like the rate design for any other electricity tariff, must follow the principles of ratemaking; more specifically, QF rates must be just and reasonable. In Addition, Act 62 requires that the Commission must establish avoided cost rates that are "just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and [] strive to reduce the risk placed on the using and consuming public."

QF rates must be developed based on credible analysis of the utility's avoided costs within the bounds of uncertain inputs and methods, which I define above as the "zone of reasonableness." Within this "zone of reasonableness," leaning toward higher rates could marginally increase customer costs, however these costs are transparent, stable, and tied to performance (i.e., the output of a given QF's resources). Moreover, to the extent higher rates encourage QF development and deployment, they can yield other benefits beyond avoided utility costs. In contrast, leaning toward lower rates within the "zone of reasonableness" could have significant negative consequences in addition to undercompensating QF resources.

Q. Please describe the risks of compensating QF resources below the costs they enable the utility to avoid (i.e., QF rates leaning toward the lower end, or outside, of the "zone of reasonableness").

A. The clearest risk of QF rates approved below a utility's avoided costs is stifled competition in the market. In addition to the lost competition to utility resources that drives down utility resource costs, the stifled competition of a QF market can be detrimental to the diversity of the utility's resource mix.

A less commonly understood but equally significant risk of low QF rates is the loss of a hedge against cost overruns associated with large traditional resource procurements. Given the fact that Duke uses the peaker method to derive their avoided capacity cost rates for QF resources, QF capacity rates are based on the overall overnight capital cost of a proxy peaker resource. [redacted].[3] As such, QF rates that err

[3] [redacted].

towards the low end of the "zone of reasonableness" creates an asymmetric risk borne on the shoulders of electric consumers. In other words, low QF rates can saddle electric consumers with both the cost overrun risk of the utility's avoided resource and the risk of lost diversity in the utility's resource mix, which could lead to more volatile operational costs and system resiliency issues. Low avoided cost rates do facilitate the utility's ability to build another resource into its rate base, adding to shareholder profits.

Q. What are the risks of lumpy, capital-intensive investments in large generation resources such as a gas combustion turbine?

A. Due to major technological innovations in the electricity sector the dynamics of energy markets across the world are changing incredibly fast. As the cost curves of emergent technologies decline at a rapid rate, the risk of stranded costs for 20- to 40-year capital-intensive traditional infrastructure investments increases at a similar rate. Below are some trends, which are not hypothetical, indicating how these market dynamics are unfolding across the United States:

- Coal plants that are still on PacifiCorp's balance sheet (and in its rate base) are operating uneconomically, i.e., losing the utility money.[4]

[4] PacifiCorp, *2019 Integrated Resource Plan Public Input Meeting*, 2018 December 3-4: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_December_3-4_2018_PIM.pdf

Studies indicate that replacing most of those plants with new wind power purchase agreements would be cheaper for the utility, even without taking the plants out of its rate base.[5]

- Utility Commissions across the country are rejecting utility plans to build new gas plants because smaller and cleaner alternatives could be cheaper.
    - The Arizona Corporation Commission instituted a moratorium on new gas plants after rejecting the IRP filed by the state's investor-owned utilities.[6]
    - The Oregon Public Utility Commission rejected Portland General Electric's (PGE) initial IRP indicating a need to possibly build one or two new gas plants. PGE found the gas plants could be avoided with small-scale solar qualifying facilities and a renewed hydro contract.[7]

[5] Energy Strategies, *PacifiCorp Coal Unit Valuation Study: A Unit-by-Unit Cost Analysis of PacifiCorp's Coal-Fired Generation Fleet*, 2018 June 20: https://www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf

[6] Utility Dive, *Arizona Regulators Move to Place Gas Plant Moratorium on Utilities*, 2018 March 15: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/

[7] Portland Business Journal, *PUC gives Portland General Electric another chance on new renewables*, 2017 August 8: https://www.bizjournals.com/portland/news/2017/08/08/puc-gives-portland-general-electric-another-chance.html

    - The Indiana Utility Regulatory Commission rejected an 850 MW gas plant proposed by the investor-owned utility, Vectren, and directed the utility to evaluate alternatives to large, centralized resources.[8]

- Utility-scale solar-paired energy storage resources are “solidly competitive” with natural gas combined cycle plants across the U.S.[9]
- The Public Service Company of Colorado selected the winning bids from its 2017 all-source solicitation to replace retiring coal plants. The selected portfolio included 1,131 MW of wind, 707 MW of solar PV, and 275 MW of battery storage and not a single MW of new natural gas.[10]

Q. Can you detail how smaller generation resources like solar QFs are less financially risky relative to traditional large-scale generation resources like gas?

A. A recent study examined 39 solar projects and found that 16 of those projects experienced cost overruns, which were on-average only 1.3 percent over their

[8] Utility Dive, *Indiana regulators reject Vectren gas plant over stranded asset concerns*, 2019 April 25: https://www.utilitydive.com/news/indiana-regulators-reject-vectren-gas-plant-over-stranded-asset-concerns/553456/

[9] Fluence, *Beyond Peaker Replacement: Solar+Storage Finds a New Job*, 2019 April 18: https://blog.fluenceenergy.com/fluence-energy-storage-solar-storage-mid-merit-utility-scale-asset

projections.[11] In contrast, of the 36 thermal plants examined in the same study, 24 of the plants overran their cost projections by nearly 13% on-average. In other words, the solar projects are significantly less financially risky than the traditional thermal resources, validating one of the study's hypotheses that decentralized and modular projects experience few and small cost overruns.[12] In addition, a key benefit of QF resources is that with PURPA-based contracts, the developers not ratepayers bear any cost overrun risk.

Q. Are there examples of cost overruns from non-QF resources that have negatively impacted South Carolina customers?

A. Yes. As has been widely reported, the construction of Units 2 and 3 at the VC Summer nuclear plant were cancelled in 2017, in part due to cost overruns during the construction process. Despite the project's cancellation, electric customers still paid over $2 billion for the uncompleted reactors.[13] This example highlights the potential risks involved with conventional generation resources. In

[10] Greentech Media, *Xcel to Replace 2 Colorado Coal Units With Renewables and Storage*, 2018 August 29: https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage
[11] B.K. Sovacool et al., *An international comparative assessment of construction cost overruns for electricity infrastructure*, Energy Research & Social Science 3 (2014) 152–160. Please see Table 1 on page 154.
[12] B.K. Sovacool et al., *Risk, innovation, electricity infrastructure and construction cost overruns: Testing six hypotheses*, Energy 74 (2014) 906-917.
[13] The Post and Courier, *S.C. utilities knew of big problems 6 months into nuclear project but didn't tell customers*, 2018 March 5: https://www.postandcourier.com/business/s-c-utilities-knew-of-big-problems-months-into-nuclear/article_0340cb3a-208e-11e8-8b74-971e7fda2095.html

stark contrast, the payment to QFs is performance-based and customers are not subject to any risk of construction cost overruns.

Q. Please describe the benefits of QF resources beyond enabling the utility to avoid certain costs.

A. Leaning towards a slightly higher value for QF rates within the zone of reasonableness can be justified by the following benefits not necessarily captured in the avoided cost frameworks, such as:

- Option value, which can enable to the utility to plan their system in a more cost-effective manner by matching generation resource needs to demand on a more precise basis;
- A hedge against risk of cost overruns of large plants;
- A long-term (i.e. 10-year) hedge against risk of fuel price uncertainty;
- Increased competition will drive prices down for customers over time;
- Support of state public policy goals such as encouraging renewable energy and local resources;
- Environmental benefits from reduced emissions and coal ash;

Q. Please describe how QF resources can provide optionality to the utility and why the option value is beneficial.

A. Investments in traditional generation resources are capital-intensive and lumpy, i.e., the investments do not occur evenly over the effective useful life of the resource but instead happen in large outlays during small intervals over the effective useful life. Committing to a capital-intensive investment causes a significant loss of flexibility that smaller, more prudent investments in the electric system such as QF resources provide by enabling the utility to adapt to future changes and leverage the rapidly decreasing costs of renewables, energy storage, and other emergent energy technologies. FERC's PURPA regulations specifically recognize this benefit of QFs, directing utilities commissions to take into account in calculating avoided cost rates "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities." 18 C.F.R. 292.304(e)(2)(vii).

Q. What are the potential cost impacts to Duke's customers if your proposed QF rates are adopted instead of the lower rates proposed by Duke?

A. I believe the impacts on ratepayers will be relatively small. For example, our proposed QF rates do not include Duke's proposed integration charge of $1.10/MWh for DEC and $2.39/MWh for DEP. Even under the most extreme solar deployment case that Duke considered (i.e. the "+1,500 MW" solar scenario), we estimate this will result in a change in total revenue requirement of <1%. The table below illustrates this:

Table 1. Illustration of impact to revenue requirements from inclusion/exclusion of integration charge.

	DEC	**DEP**
MW of Solar (+1500 Scenario)	3020	4610
Percent assumed to be deployed in SC	30%	30%
Capacity Factor (based on a SAT system located in SC)	18.90%	18.90%
MWh output (SC portion)	1,500,010	2,289,750
Duke's Proposed Integration Charge ($/MWh)	$1.10	$2.39
Total Integration Charge Collected from SC QFs (millions)	$ 1.7	$ 5.5
Estimated Annual Revenue Requirement ($millions, SC-only)[14]	$ 1,720	$ 603
Integration Charge as % of total Rev. Req.	0.1%	0.9%

Thus, even in the most extreme case, the inclusion of Duke's proposed integration charge will potentially save SC customers <1% on their electric bills. In contrast, eliminating the integration charge would yield a negligible bill impact, while providing end-use customers with stable energy costs from QF resources over the next 10 years that are not subject to fluctuations in volatile commodity costs.

[14] Based on DEP's and DEC's 2018 general rate cases in docket numbers D-2018-319-E and D-2018-318-E

V. AVOIDED COST ENERGY RATES

A. General Critique of Methodology, Inputs, and Assumptions

Q. Please describe the methodology Duke has used to calculate avoided energy cost rates as you understand it.

A. Duke estimates the hourly cost of electricity production on its system for each hour over the next ten years. This estimation is done through the use of a production cost simulation that considers many variables including Duke's future generation resources, transmission constraints, and projections regarding commodity fuel costs. Production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost. The model is run for both a "Base Case" reflecting the status quo, and a "Change Case" reflecting the addition of a 100 MW QF generator. The hourly energy cost for each case is determined and the difference is then used to determine an hourly avoided energy cost. These hourly values are then combined to develop annual average avoided energy cost values for each of nine different pricing periods in each year from 2020-2029. The annual values for each pricing period are then used to produce a levelized 10-year value, which is finally adjusted to account for various factors such as transmission line losses, working capital, and SC excise taxes.

Q. Do you have any concerns that certain assumptions or methodologies may be biased or incorrect in Duke's avoided energy cost calculations?

A. Yes, I have several concerns, as follows:

1. Duke's hourly modeling results show a significant fraction of hours that have *negative* avoided costs, despite the Base Case having positive marginal cost values in over 99% of hours.
2. Duke has developed avoided energy cost values for DEP that appear to combine model results from both the DEP East and DEP West systems, however it is not clear how the results were combined to produce single DEP values for South Carolina.
3. Duke's selection of pricing periods artificially reduces the avoided energy cost rates for DEC during hours when solar resources are available.
4. The method for calculating avoided energy costs rates for non-Standard Offer, large QFs is not fully transparent.

i. *Negative Avoided Energy Cost Values*

Q. What are your concerns related to negative avoided energy cost values?

A. I am concerned by the large number of hours in which Duke's modeling has projected avoided energy cost values that are negative. In DEC, [redacted] of the avoided cost hours calculated for 2019-2029 are negative, while [redacted] are negative in DEP.[15] During the critical summer peak periods, when both demand is high and solar resources are available, the number of hours with negative avoided costs is as high as [redacted] or more for both DEC and DEP. The presence of these negative values depresses the resulting averages used to set Duke's avoided cost rates. When summed across all hours, I estimate that the presence of negative values results in a [redacted] reduction in total avoided costs (and corresponding QF revenues) for DEC and a [redacted] reduction for DEP. I'm concerned that the high frequency of negative values may be due to an artefact of Duke's modeling, rather than what is likely to occur in real-world operations.

Q. For the majority of hours, why does the addition of QFs lead to a positive avoided cost value?

A. Under most circumstances – both in real-world operations and in the production cost model – the addition of a QF resource would reduce the overall load that Duke needs to serve with its own resources. Thus, the marginal generator that is online can be redispatched at a lower level of output, thereby saving fuel and operating costs corresponding to the marginal cost of that generator. In this

15 [redacted]

case, I would expect the avoided cost to closely match the marginal cost of generation under the Base Case.

Q. What might cause the avoided cost to differ from the marginal cost under the Base Case?

A. Constraints built into the model such as transmission limits, generator minimum loading levels, generator ramp rates, and so on may require a different generator than the marginal unit to back down due to the QF addition. Additionally, the addition of the QF resources might lead to a different set of units being committed, and in turn, a different set of marginal costs under the Change Case. To the extent QFs reduce load, they can reduce the number of unit commitments, thereby reducing generator startup costs, thus increasing avoided costs above the marginal cost value. These modeling constraints may bear no relation to real-world conditions or the actual operation of Duke's system.

Q. Is it possible for avoided energy costs to be negative during some hours?

A. Yes, it is possible. Generally speaking, I would expect this to occur when the marginal generator is a baseload plant (e.g. nuclear) operating at or near its minimum loading level during light load conditions. In this case, the addition of the QF may require the baseload plant to operate below its minimum which is infeasible. Instead, the model would decommit the baseload plant and replace it with a higher marginal cost generator that does not have the same minimum loading constraints.

Q. Would you expect the frequency of negative values to occur as often as Duke modeling suggests?

A. It is difficult to say with certainty without further review of the model. However, the frequency does seem high enough to suggest there may be certain modeling assumptions that are driving this outcome which may not match reality. For example, I would expect negative values to correspond with periods of low load, when baseload generators may need to be replaced as described above. However, that does not appear to be the case. The below charts illustrate how negative avoided cost values directly overlap with summer peak loads for DEP. I observed a similar trend for DEC's where summer peak avoided costs are negative over [redacted] of the time.

[redacted]

Q. Has Duke provided sufficient detail on the inputs to its production cost model to be able to review and understand the drivers of these negative values?

A. No. Duke has provided the confidential results showing the hourly marginal costs for its base case but has not provided marginal cost results for its change case. I have analyzed the provided information to the best of my ability given these data limitations. Additionally, Duke has not provided some of the key input parameters, such as transmission constraints or “must-run” designations which could be key factors in explaining these trends. SBA intends to request additional information from Duke on these issues.

Q. What do you recommend to resolve this issue?

A. First, I suggest that more information be provided on Duke’s production cost model to understand the patterns driving these negative avoided costs. If the negative values are found to be driven by any artificially constraining inputs, the model should be rerun with these constraints removed or sufficiently relaxed. Second, since modern QFs (including solar) are largely dispatchable, it is possible that QFs could avoid any negative pricing periods altogether and deliver even greater savings to South Carolina ratepayers through strategically timed curtailment. As mentioned above, this could amount to a 28-30% increase in total avoided costs. Recognizing that a PPA that gives the utility dispatch rights over a solar QF is not PURPA compliant (unless the QF has a PURPA-compliant alternative), I suggest an optional pricing scheme could be developed that removes some level of the negative values in exchange for some level of dispatchable operations.

ii. Fuel and Commodity Costs

Q. Why are accurate commodity prices important to the avoided energy cost calculations?

A. Commodity prices are one of the key inputs that influences the avoided energy cost rates. Duke derives avoided energy rates, levelized over the next ten years, by modelling marginal energy costs at the power plants across its system. Mr. Snider's testimony asserts that natural gas "is often the marginal resource."[16] However, confidential data made available in response to discovery questions from ORS[17] [redacted]

[16] Glen Snider Direct Testimony. P.24.
[17] "[redacted]

[redacted][18]. Therefore, the commodity prices that Duke uses for both coal and natural gas have a significant influence on the avoided energy cost rate, making it very important to closely examine Duke's assumptions about these prices. Prices that are too high or too low could strongly bias the resulting rates. Historically, natural gas prices have fluctuated dramatically. While they have stabilized in recent years due to the availability of shale gas, there is still uncertainty.

Q. Do you believe Duke's proposed natural gas and coal prices are appropriate?

A. We are continuing to evaluate these prices and may update our position based on that analysis.

Q. What is the relevance of a fuel hedge to the avoided cost rates?

A. A fuel hedge is an important component of fuel costs, particularly for more volatile commodities such as natural gas. A fuel hedge helps ensure that Duke is not vulnerable to commodity price fluctuations and generally comes at an additional to the commodity itself. Since payments to QFs have no price

[18] We have formally requested data on marginal energy resources and we are awaiting Duke's discovery response.

volatility, a hedge is automatically included and its value should be included in the avoided energy cost calculation. We have requested confirmation via discovery that Duke included a fuel hedge in its avoided energy costs and are awaiting response.

iii. Large QF Output Profile

Q. What avoided energy cost rates is Duke proposing for "non-Standard Offer PPA QFs" (i.e. those greater than 2MW)?

A. Duke proposes to "take the specific supply characteristics or 'resource type' of the QF into account", including "using a solar generation profile for solar QFs"[19]. This method differs from Duke's Standard Offer peaker methodology, which adds a hypothetical 100MW of no-cost generation to the utility's "base case" generation fleet[20] without distinguishing between resource type or specifying resource output.

Q. Does Duke provide any approximation of rates for a representative non-Standard Offer QF resource, such as a solar PV resource?

[19] Joint Application of Duke Energy Carolinas and Duke Energy Progress, LLC, for Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Other Related Terms and Conditions. p.12-13.
[20] George Snider Direct Testimony. P.22.

A. No. At this stage, there is no way to determine in advance what avoided cost rates will emerge from Duke's avoided cost calculation for a non-Standard Offer QF.

Q. What justification does Duke offer for changing its peaker methodology for non-Standard Offer PPA QFs?

A. Duke claims that the alternate methodology for larger QFs will "more accurately reflect the Companies' most current forecast of avoided costs"[21]

Q. What is your interpretation of this statement?

A. This suggests to me that 1) Duke believes there are potential inaccuracies in the Standard Offer avoided cost rates, and 2) the non-Standard Offer calculation is likely to include methodological choices that have not been made transparent in this proceeding.

Q. Do you think it is appropriate to use a different methodology for non-Standard Offer QFs? Why or why not?

A. No. Not only should the Standard Offer rates already be accurate, I believe avoided costs rates should also be kept consistent across QF contracts. It is

[21] George Snider Direct Testimony. P.29.

unclear why the Standard Offer peaker methodology would not already be representative of the Companies' avoided energy costs. Given that South Carolina provides for updated avoided cost calculations on a regular basis, the avoided cost rates should already be kept up to date as additional QFs are added to the system. Additionally, the peaker methodology should be applied in the same way for Standard Offer and non-Standard Offer QFs. Given that the Standard Offer methodology accounts for 100MW of displaced generation, this approach should be well-suited to QFs larger than 2MW. The technology-neutral approach of the Standard Offer is appropriate for large QFs as well since it anticipates the possibility of not just solar QFs, but also solar pared with storage which is increasingly common and does not necessarily adhere to a fixed output profile.

Q. What do you suggest that Duke should do differently in its treatment of large QFs?

A. Duke should treat Standard Offer and non-Standard Offer QFs the same way under the peaker methodology. The avoided energy cost rates for each type of QF should be technology neutral.

iv. ***Environmental Costs***

Q. Are there environmental harms and associated environmental costs that QFs mitigate?

A. Yes. While the Companies' avoided energy cost rates include avoided emission control reagents and allowance costs for sulfur dioxide and nitrogen oxide,[22] they fail to include the significant coal ash costs that could be mitigated by qualifying facilities.

Q. Do you have any examples of such coal ash costs?

A. Yes. Under Docket No. 2018-319-E, DEP recently requested recovery of $635,040,092[23] in coal ash expenses, while DEC requested $876,206,294[24]. This $1.5 billion in proposed ratepayer costs reflects the significant liability of continued coal plant utilization. QF resources such as solar PV involve none of these prospective costs. To the extent that solar QFs displace coal generation, they can play a role in minimizing future coal ash expenditures borne by ratepayers.

[22] George Snider Direct Testimony. P.28.

[23] Direct Testimony and Exhibits of Dan J. Wittliff, P.E., BCEE on behalf of the South Carolina Office of Regulatory Staff Docket No. 2018-318-E in Re: Application of Duke Energy Progress, LLC for Adjustment in Electric Rate Scheduled and Tariffs and Request for an Accounting Order

[24] Direct Testimony and Exhibits of Dan J. Wittliff, P.E., BCEE on behalf of the South Carolina Office of Regulatory Staff Docket No. 2018-318-E in Re: Application of Duke Energy Carolinas, LLC for Adjustment in Electric Rate Scheduled and Tariffs and Request for an Accounting Order

Q. Is coal likely to be displaced by solar QFs in South Carolina?

A. Yes. [redacted] Thus, as solar QFs are brought online, they are very likely to reduce the amount of coal burned at the marginal units in Duke's fleet. This in turn will reduce the volume of coal ash that is produced at these plants and help alleviate the burden of future coal ash disposal.

Q. Were reduced coal ash costs included in Duke's proposed avoided energy costs for QFs?

A. Not as far as I can tell based on the information provided by Duke.

v. <u>Treatment of DEP Balancing Areas</u>

Q. Are there other distortions that you believe may have biased Duke's avoided energy cost rates?

A. Yes. The rates used in DEP reflect both an eastern and western balancing authority for the utility; however, Duke reports avoided energy costs as one value for DEP. This methodology might make sense if the marginal resource and associated costs were identical for each BA, but this does not appear to be the case.

Q. How do the marginal costs in each balancing authority differ?

A. To determine that the east and west BAs have different marginal energy costs, we first confirmed that different resources are marginal in each. [redacted]

[redacted]

[redacted]	[redacted]			
[redacted]	[redacted]			
[redacted]	[redacted]			
[redacted]	[redacted]			

[redacted]

[redacted]

Q. Why is it inappropriate to represent the avoided costs in DEP East and West as one value?

A. Combining the two BAs means that the cheaper marginal cost in DEP West puts a downward pressure on avoided cost energy rates in DEP East, which is where QF development can only occur in South Carolina (DEP West is located in North Carolina).

Q. Has Duke provided workpapers demonstrating how the hourly avoided costs for the DEP East and DEP West systems were combined into a single DEP avoided cost rate?

26 [redacted]

[redacted]

A. No.

Q. What alternative would you propose for DEP's alternative energy cost rate design?

A. I would recommend separating the avoided costs of DEP East and DEP West since the modeled marginal costs for each system appear to be quite different. Additionally, it appears that the service territory for DEP West (formerly Carolina Power and Light West) is located solely in North Carolina and does not directly serve South Carolina customers. This way an avoided energy cost could be developed for QFs that interconnect to each system. This would be more accurate in terms of the avoided energy costs at each particular location. A more location-specific approach is not only more accurate, but also comports with relevant legal standards.

B. Rate Design & Selection of Pricing Periods

Q. What pricing periods is Duke proposing for its avoided energy rate design?

A. Duke has proposed nine energy pricing periods for its avoided energy rates: summer premium-peak, on-peak, and off-peak; winter premium-peak, on-peak (AM and PM), and off-peak; and shoulder-season on-peak and off-peak.

Figure 3: Avoided Energy Rate Design Pricing Periods

Energy Rates																		
Independent Energy Price Blocks	1.Summer Premium Peak (PM)		2.Summer On-Peak (PM)		3.Summer Off-Peak		4. Winter Premium Peak (AM)		5.Winter On-Peak (AM)		6.Winter On-Peak (PM)		7.Winter Off-Peak		8.Shoulder On-Peak		9.Shoulder Off-Peak	
Company	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP
10-Yr Rate (cents/KWH)	4.58	3.30	4.48	3.11	2.60	2.68	5.04	3.58	4.61	3.54	4.15	3.42	2.70	2.75	3.39	2.98	2.28	2.26

<table>
<tr><th>DEC Energy Hour Ending</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer (Jun-Sep)</td><td colspan="12">3.Off</td><td colspan="4">2.On (PM)</td><td colspan="4">1.Premium</td><td colspan="2">2.On (PM)</td><td colspan="2">3.Off</td></tr>
<tr><td>Winter (Dec-Feb)</td><td colspan="5">7.Off</td><td>5.On</td><td colspan="3">4.Premium</td><td>5.On</td><td colspan="7">7.Off</td><td colspan="5">6.On (PM)</td><td colspan="2">7.Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="6">9.Off</td><td colspan="4">8.On</td><td colspan="6">9.Off</td><td colspan="7">8.On</td><td>9.Off</td></tr>
<tr><th>DEP Energy Hour Ending</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
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<tr><td>Winter (Dec-Feb)</td><td colspan="4">7.Off</td><td colspan="2">5.On (AM)</td><td colspan="3">4.Premium</td><td colspan="2">5.On (AM)</td><td colspan="7">7.Off</td><td colspan="4">6.On (PM)</td><td colspan="2">7.Off</td></tr>
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</table>

Figure 3. Duke's Proposed Pricing Periods

Q. Why is the selection of pricing periods significant for solar QFs?

A. First, it is important to recognize that the number of pricing periods and the exact hours included within each period is a subjective decision. However, the choice of pricing periods has significant implications for computing the avoided cost rates that ultimately impact solar QF revenues. Since each rate period reflects an average of underlying avoided cost values, it is possible to skew the avoided cost rate higher or lower for any individual hour within a given time period due to the effects of averaging. This is particularly significant for solar QFs whose production may overlap with some hours within a time period, but not all hours.

Q. Do you think all of the pricing periods selected by Duke are appropriate? Why or why not?

A. Not exactly as proposed. Duke's proposed rate design arbitrarily reduces the avoided energy cost rate during several key solar QF production hours by averaging these hours with lower value hours. For example, Duke has selected a very long summer off-peak period for both DEP and DEC (fourteen and sixteen hours, respectively). In DEC, the summer off-peak period runs from 10pm through 12pm the following day. Using such a long period allows the Companies to average summer daytime hours, when avoided costs are generally higher, with nighttime hours, when avoided costs are generally lower. This succeeds in lowering the avoided cost rate for those morning hours (when solar QF output is available) below what it would be if they had their own pricing period. Similarly, Duke has proposed unnecessarily broad off-peak periods during the shoulder seasons. The selection lumps the low-cost overnight hours in with six higher-cost hours from mid-morning to mid-afternoon, once again averaging down the avoided energy costs during a period when solar could valuably contribute to Duke's power system, if provided an accurate economic signal to do so.

Q. Is there any reason you can think of that the time periods need to be structured in the way that Duke has proposed?

A. No. It is not necessary nor economically efficient to divide the summer or shoulder pricing periods in this way. The Companies used hourly avoided cost data to create average rates for each period, which means that the pricing periods could easily be more granular. In the extreme case, avoided energy costs could even be priced on an hourly basis if desired, rather than grouped into pricing periods. Importantly, having more precise and representative rates would send a more efficient price signal to QF developers who otherwise may be less compelled to invest, despite the higher electric-system value of their morning summertime and mid-day shoulder season production. For example, as demonstrated below, there is a clear distinction between the weekday overnight prices and weekday morning prices in the summertime in DEC. The hours outlined in red represent the summer peak period that I have recommended, which offers distinctly more value than the overnight hours Duke originally averaged it with.

[redacted]

Figure 4: DEC Avoided Energy Costs ($/MWh) During Summer Weekdays, Averaged Hourly by Year[28]

The arbitrary selection of time periods undervalues the true daytime avoided cost, therefore biasing against daytime QF production such as solar power. A different selection of pricing periods would more accurately reflect avoided cost and could significantly affect solar compensation. In the next section, I propose an alternative such structure.

C. Calculation of Alternative AC Energy Rates for DEC

Q. What changes do you propose to DEC's avoided energy cost rate methodology?

A. I propose the inclusion of two new avoided energy cost pricing periods, based on my above explanation that the utility has selected unnecessarily long off-peak periods in the summer and shoulder seasons. This modest change would not only send QF facilities a more accurate price signal, but also helps to remove some of the bias against solar QFs during summer mornings and mid-day periods in shoulder months.

28 [redacted]

Q. What two new pricing periods do you recommend?

A. Using Duke's proposed DEC pricing periods as a starting point, I recommend minor modifications that would create two new pricing periods as follows:

1) a Summer On-Peak (AM) period

2) a Shoulder Mid-day period.

The Summer On-Peak period would be created by splitting DEC's current Summer Off-peak period (e.g. 10pm - 12pm) into two periods: Summer On-Peak (AM), and Summer Off-peak. I propose that Summer Off-peak run from hour-ending 23 through hour-ending 7 (rather than 23 to 12), and that Summer On-peak (AM) run from hour-ending 8 through hour ending 12.

The Shoulder Mid-day period would be created by converting DEC's current Shoulder Off-peak period in the middle of the day (e.g. 10am - 3pm) into its own "Mid-day" pricing period. The overnight Shoulder Off-peak period would remain the same. Below, I illustrate my proposed additions (highlighted in yellow).

DEC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	Off							On (AM)					On (PM)				Premium				On (PM)		Off	
Winter (Dec-Feb)	Off					On (AM)	Premium		On (AM)		Off							On (PM)					Off	
Shoulder (Remaining)	Off						On				Midday					On								Off

Q. How did you choose these time periods?

A. Using Duke's hourly avoided cost data, I determined the average hourly avoided energy costs for each season over the next ten years. I then identified suitable alternative time periods by grouping similarly-valued summer morning weekday hours that were distinct from summer weekend and overnight hours; and by grouping the shoulder mid-day hours that are distinct from the shoulder weekend and overnight hours.

Q. What impact do the proposed alternate energy pricing periods have on solar QF value?

A. In order to calculate the additional QF value, [redacted] I then multiply the changed summer AM, summer off-peak, shoulder mid-day, and shoulder off-peak levelized rates by a representative South Carolina solar summer output during those time periods. I find that the total annual revenue of a hypothetical 100kW solar QF on the DEC system increases by [redacted] under my proposed time periods. Not only do the rates in my proposed time periods better match the avoided energy costs that the utility has calculated; they also increase solar compensation, thereby encouraging further QF production, and helping meet the policy goals of the state.

Q. What are the resulting avoided energy costs based on your calculation?

A. The alternative avoided energy costs are provided in the table below. These can be further adjusted to produce avoided cost rates using Duke's method.

[redacted]

A.

<u>Calculation of Alternative Avoided Cost Energy Rates for DEP</u>

Q. Do you recommend an alternative for DEP at this point in time?

A. I believe more information is needed from Duke to fully develop an alternative. As explained above, Duke has not yet provided information regarding how it combined avoided cost values from the DEP East and DEP West systems to develop a single DEP avoided cost. It is critical to isolate the Avoided Cost energy values for DEP East as DEP West is located solely in North Carolina. Without separate avoided energy cost information, it is not possible to evaluate and propose representative rates. It is likely that adding a couple hours onto DEP's summer peak period (e.g. 12 and 13), winter PM peak (e.g. 16, 17, and 18) and shoulder peak (e.g. 17) could better align the rates with their underlying hourly avoided costs. When we receive this additional data from Duke, we will analyze that possibility. However, in the absence of more information, I believe an interim solution could be implemented that reasonably approximates avoided costs for each.

Q. What do you propose as this interim solution?

A. The major difference between the DEP East and DEP West systems is the resource that sets the marginal cost during the vast majority of hours. In the case of DEP East [redacted] and in the case of DEP West [redacted].[29] As mentioned previously, I estimated the marginal cost of Duke's coal units to be at least [redacted] than that of a future gas CC unit, and even higher in some years. As such, I propose an adjustment to Duke's proposed avoided costs for DEP depending on whether a QF is located in the East or West region. This would result in an increase in the QF rates for DEP East [redacted]. It would also more accurately reflect the location-specific value of avoided costs on DEP's system. For example, based on [redacted], the avoided energy cost for DEP East could be adjusted

[29] Percentages reflect a 10-year average

upward (e.g. [redacted]) and the avoided energy cost for DEP West could be adjusted downward (e.g. [redacted]).

VI. AVOIDED COST CAPACITY RATES

A. General Critique of Methodology, Inputs and Assumptions

Q. Have you reviewed Duke's proposed approach to calculating avoided capacity costs for the purpose of setting an avoided capacity rate under PURPA?

A. Yes.

Q. Do you believe Duke's proposed method is appropriate?

A. Partially. I believe the general framework (i.e. the Peaker Methodology) is sound. However, there are specific assumptions and methodological choices that I believe are incorrect and biased against QFs and solar QFs in particular. These flawed assumptions and methods underestimate the true avoided capacity costs for both DEP and DEC and the corresponding rates Duke has proposed.

Q. What assumptions or methodologies are you concerned may be incorrect and biased against solar QFs?

A. There are several. Briefly, my concerns about avoided capacity costs relate to the following key assumptions:

- The seasonal weighting allocations of capacity value based on the LOLH study.
- The assumed capital cost of a new peaker in terms of the technology type, assumed economies of scale, and associated fixed costs.
- The timing of assumed capacity value from a QF facility.

I will describe each of these in more detail in my testimony below.

i. <u>Seasonal Allocation</u>

Q. How does Duke consider the need for new capacity resources in terms of season and time of day?

A. Duke considers itself to be primarily a winter peaking utility, though it has peak load hours in both winter and summer months. Duke's analysis indicates that the highest hours of capacity need occur during three different time periods: 1) the summer afternoon/evening, 2) winter morning, and 3) winter evening. Capacity value is then allocated to these time periods based on their relative weightings and in turn used for determining the avoided cost rates for capacity.

Q. Do these seasonal allocation factors have a significant effect on solar QF revenues?

A. Yes, very much so. Since very little solar energy is available during the Duke-defined wintertime periods, higher winter allocation factors (and correspondingly lower summer factors) will lead to lower overall revenues for solar QFs. For example, I estimate that shifting just 10% of the capacity allocation from the Winter ~~A~~P.M. period to the Summer P.M. period for DEC would increase solar QF capacity revenues by over [redacted]%.[30] A similar 10% shift for DEP would increase solar QF capacity revenues by [redacted]%. As such, the allocation factors have an outsized impact on the ability for QFs to obtain fair compensation in exchange for the capacity value they provide.

Q. Do you believe the seasonal allocations modeled by Duke may be incorrect and biased against solar QFs?

A. Yes. Duke's estimation of the seasonal allocations are largely based upon a study it commissioned (conducted by Astrape Consulting) to determine the capacity value of solar.[31] As part of this study, Astrape modeled the probability

[30] [redacted].
[31] Confirmed in Duke's response to SBA Int 2-2.

of Loss of Load Hours (LOLH) over many potential scenarios on Duke's system using its SERVM model. The distribution of the LOLH was then used to determine how the avoided capacity value (and corresponding rates) should be distributed across the year. However, there are a variety of assumptions included in this analytical model that may have biased the distribution of LOLH hours towards the early morning in winter months, rather than the afternoon in summer months when solar resources are more available.

Q. Has Duke's underlying capacity value study been critiqued in other jurisdictions?

A. Yes. In fact, the North Carolina Utility Commission recently issued an Order in its IRP proceeding[32] requesting further comments from parties including the Public Staff, SACE, and NCSEA, and scheduled oral arguments on Duke's reserve margin findings, which are directly tied to the Astrapé Resource Adequacy Studies and incorporated into both the Astrapé Capacity Value and Ancillary Services studies used in this proceeding.

[32] August 27, 2019 Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analysesin Docket E-100 Sub 157

Q. What assumptions in the Capacity Value Study do you think could possibly lead to a biased outcome?

A. Some of the key assumptions include the following:

- Underlying load forecasts for DEC and DEP;
- Differences in the availability of demand response in winter and summer months;
- Characterization of neighboring utility load, transmission constraints, and corresponding availability of neighbor support during summer and winter months;
- Seasonal variations in assumptions for forced outage rates and planned maintenance.

Q. Can you explain why each of these assumptions may be inadequate for accurately determining the seasonal allocation for capacity?

A. Yes. I will address each of these below.

Q. What are the relevant considerations of the DEC and DEP load forecast as it relates to seasonal capacity value?

A. As confirmed in SBA Int 2-2c, the seasonal allocations values were based upon the LOLH analysis conducted as part of the Astrape Capacity Value study. Moreover, as detailed in Duke's response to ORS Request 2-18, this study included “2020 assumptions for load forecast” and confirmed that “To the extent the native load shape changes over time such impacts will be incorporated in future studies.” Thus, the current study includes no consideration of how load, and the resulting allocations might shift over time. It is entirely plausible that load growth and load shapes will shift over the next 10 years. For example, if summer load grows faster than winter load, it will tend to shift the allocation back towards summer hours. However, this possibility is not considered as part of Duke’s analysis, despite the fact they the Company is projecting load over the same 10-year time horizon.

Q. What are the relevant considerations for Duke’s analysis as it relates to demand response?

A. As outlined in the Solar Capacity Value study, Duke assumes the following: “For 2020, DEC assumed 1,031 MW of demand response in the summer and 406 MW in the winter. DEP assumed 1,015 MW of summer capacity and 512 MW of winter capacity.”[33] Thus, Duke assumes half of the demand response resources are available in summer as are available in winter. While this may be a reasonable assumption based on current demand response contracts and availability, a more concerted effort by Duke to target and mitigate extreme

[33] See Astrape Consulting Solar Capacity Value Study, p 30.

winter peak events could shift the balance of these resource towards winter and the resulting seasonal allocation towards summer.

Q. Have you attempted to determine the impact additional winter demand response resources would have on the seasonal allocation results?

A. Yes, however unsuccessfully. I requested (via SBA) for Duke to provide the seasonal distribution of loss of load risk assuming winter demand response was equivalent to summer values. Duke responded by saying that it "has no information to provide in response to this request." [34]

Q. What are the relevant considerations for Duke's seasonal allocation of capacity value as it relates to neighbor assistance?

A. As stated in Wintermantel Exhibit 2, p 13, "For Resource Adequacy and Solar Capacity Value studies, neighbor assistance capacity plays a significant role in the results." SBA has pending information requests related to this and I may update my position based on these responses. In the meantime, I believe it is worth noting that DEP and DEC are both neighbors to several summer peaking utilities that are likely to have available resources to contribute to winter peaking needs. This would serve to alleviate DEP and DEC's winter peaking problem,

[34] See Duke response to SBA Int 2-8.

and potentially increase the summer capacity allocation for QFs. However, it is possible that this contribution may be artificially limited in Duke's modeling due to assumed transmission constraints. SBA is still awaiting more information from Duke on the availability of neighbor assistance as it relates to resource adequacy and the capacity value study and may provide additional updates to this position accordingly.

Q. Have you reviewed any other information that may relate to Duke's model inputs for neighbor assistance?

A. Yes. Duke provided information on SERVM model inputs for its Ancillary Services study in response to SBA RFP 1-1. This appears to include inputs related to "Transmission Capability" to and from neighboring balancing areas. While I can't be certain that the same model inputs were used for the capacity allocation study, it is worth noting that these inputs include several [redacted].

Q. Do Duke's proposed allocations make sense based on historical load data for DEC and DEP?

A. Not based on my analysis. [redacted]

[redacted],

[redacted]

Q. In the aggregate, what is the significance of the modelling flaws you describe above?

A. Duke's use of a static load forecast assumptions, limited demand response assumptions, and an emphasis on a few hours of extreme winter weather events rather than on the vast majority of historical summer peak load hours results in a seasonal allocation weighting that is significantly biased and fails to recognize or incorporate the full capacity value that solar generators provide.

Q. Do you recommend a different seasonal allocation from what Duke has proposed?

A. Yes. I recommend that the seasonal allocation that reflects this historical pattern as shown in the table above. I believe this is a simple and transparent approach and is an accurate representation of when Duke's historical peak loads have occurred. Additionally, this avoids any potential influence from opaque modeling approaches and associated inputs. I may propose a more specific allocation later pending additional information from Duke on some of the key inputs and assumptions used in its model as described above.

ii. New Peaker Capital Costs

Q. What has Duke's proposal assumed regarding the capital cost of a new peaker (i.e. the marginal cost of new capacity)?

A. Duke has proposed that the marginal cost of new capacity be based on a peaker unit with an initial capital cost of $677/kW. This is based on the EIA's 2019 Cost and Performance Characteristics of New Generating Technologies Table in their Annual Energy Outlook, considering a regional cost adjustment for the SERC VACAR Region, and an inflation adjustment. Duke also considers an adjustment factor for ‘economies of scale’, which reduces the initial capital cost by [redacted]. Duke argues that this adjustment is warranted since building a 4-unit combustion turbine (CT) plant would reduce the per-unit cost of each unit due to common costs associated with land, buildings, roads, security, gas interconnection, and other infrastructure relative when compared to a single 237 MW unit.

Q. Do you believe Duke’s assumed capital cost of a new peaker is incorrect and potentially biased against QFs?

A. Yes. For calculating the avoided capacity costs, Duke has selected the lowest cost available peaking unit included in EIA’s predetermined list of potential generation technologies. This does not necessarily correspond to the cost of the peaking unit that Duke would ultimately select to meet future peak demand or provide other services.

Q. What other types of peaking units might be appropriate for Duke to consider in its selection?

A. Recently, there has been a growing trend towards more flexible, aeroderivative types of peakers. For example, in PJM, aeroderivative CTs recently outnumbered conventional frame CTs (Duke’s selection) in both project count and capacity. For instance, a recent report on new capacity in PJM noted 12 aeroderivative projects totaling 714 MW versus only 3 frame projects totaling 481 MW.[35]

Moreover, Duke's own proposal in this proceeding suggests that there will be significant future solar integration costs that may lend themselves towards installing more flexible types of peaking unit that can better respond to variable generation in order to mitigate these integration costs. While these flexible types of peaking units are generally more efficient and more responsive to the grid's needs, they are also more expensive in terms of upfront capital costs.

[35] "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date", The Brattle Group, 2018, p. 15.

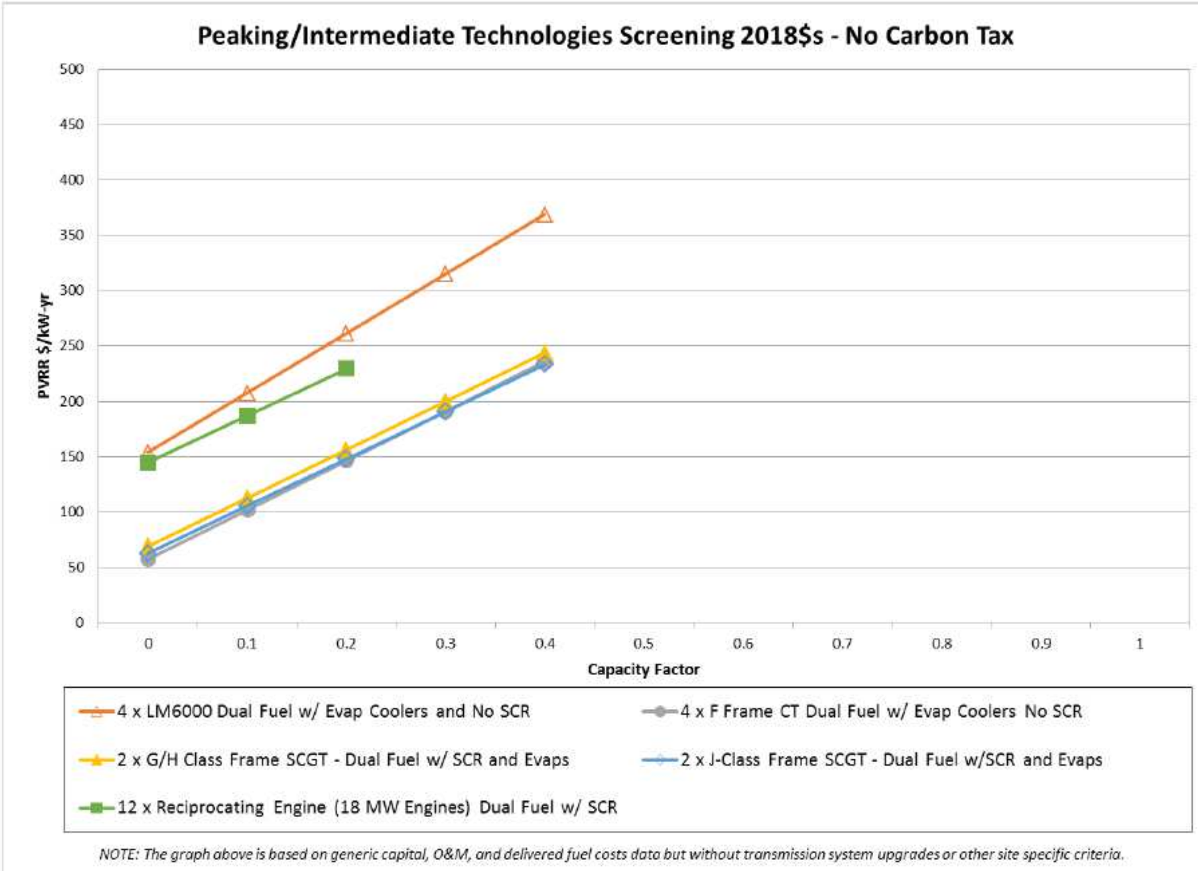


Figure 4. Peaker technology cost screen from Duke's 2018 IRP

For comparison, Duke’s 2018 IRP suggested that the fixed costs of an aeroderivative CT (LM6000, 0% capacity factor) was approximately 2-3 times that of an advanced frame CT (see Figure 4 above). This is consistent with cost estimates I have observed from other utilities. For example, in its 2018 IRP

Dominion Energy Virginia projected an overnight capital cost of an aeroderivative CT of $1,680/kW.[36]

Q. What do you recommend instead of using Duke's assumptions for peaker capital costs?

A. Given the recent trends towards more flexible peaker technologies that can meet both peaking and ramping needs, I believe it is appropriate to consider a different initial capital cost than what Duke has proposed. While the EIA cost assumptions are reasonable for a frame CT, they are not reasonable for an aeroderivative CT or internal combustion engine (ICE). Meanwhile, there is sufficient reason to believe that one of these more flexible types of peakers will in fact be the marginal capacity resource due to both market trends and evolving grid needs. As such, I propose a capital cost assumption of $1,178/kW which represents the midpoint of these the two classes of peaker technologies.[37]

Q. How else is the capital cost of the peaking unit assumed by Duke biased?

A. In addition to selecting a very low-cost unit, Duke also applies an "economies of scale" factor to further reduce the initial capital cost of the unit. This assumes

[36] Dominion Energy Virginia 2018 Integrated Resource Plan, Appendix 5B: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf
[37] Based on Duke's estimate of $667/kW and Dominion's estimate of $1680/kW.

that to satisfy its future capacity needs, Duke would build not one 237 MW peaker unit, but four separate units, for a total of 948 MW. Duke then uses this 948 MW plant as the basis for computing the avoided capacity cost for its Standard Offer, which reflects a representative 100 MW QF.

Q. Is this a reasonable assumption?

A. I do not believe so. Given its extraordinary size, I do not believe a 948 MW plant is representative of what Duke is likely to build in the near term to satisfy its peaking needs. Doing so would likely lead to a significant overbuild of capacity and a significant additional cost to customers. I believe it is more likely that the marginal capacity unit would be a single 237 MW peaking unit (with reduced economies of scale) or a series of ~100 MW aeroderivative units as described above. In this case, Duke's assumption serves to further depress the avoided capacity cost, hindering the valuation of QFs.

Q. What other factors may be underestimated in the peaker plant capital costs in Duke's proposal?

A. In addition to the generation resource itself, installation of a new power plant generally requires additional capital expenditures in the form of upgrades to the transmission and distribution network. As Duke has acknowledged, the EIA estimate of assumed peaker plant capital costs "does not include significant transmission system upgrades."[38] These should be included to more accurately reflect the true avoided cost.

Q. What would you recommend as an assumption for transmission upgrade-related costs associated with a new peaker?

A. In Minnesota, Xcel Energy's 2016-2030 Upper Midwest Resource Plan estimated the capital costs of transmission associated with a new peaker (CT unit) to be \$152/kW.[39] To be more conservative I suggest a value of \$120/kW be included in Duke's avoided cost calculation.

Q. Would the avoided capacity costs vary if Duke were to use your recommendation that considers the cost of an aeroderivative peaker? If so, by how much?

A. Yes. According to Duke, the NPV over a 10-year period when considering their selected 4-unit reference CT plant is [redacted]

[38] See Duke's response to SBA Int 2-5b.
[39] See Xcel Energy's 2016-2030 Upper Midwest Resource Plan, Appendix J, p 16.

[redacted].[40] This is based on the data and methods employed by Duke as demonstrated in Snider Confidential Exhibit 1 DEC and Exhibit 1 DEP. It is relatively straightforward to estimate the Net Present Value (NPV) when considering a new peaker, as Duke did, based upon a different technology cost assumption such as that mentioned above of $1,178/kW with a $120/kW transmission adder ($1,298/kW total). Using the cost assumption described above and assuming identical capacity to that of the CT unit used by Duke (237 MW), I used the methodology Duke employed in “DEC_FCR-Confidential-.xlsm” and “DEP_FCR-Confidential-.xlsm” to determine the comparative 10-year NPV for both the distribution and transmission level for DEC and DEP, respectively. For DEC the values are [redacted]. For DEP the values are [redacted].

Q. Why does the avoided capacity cost value for DEC and DEP differ so significantly despite the same capital cost assumptions?

[40] Based on George Snider Direct Testimony, Confidential Exhibit 1 DEC and Confidential Exhibit 1 DEP, Tab titled ‘Page 7-8’, row 41.

A. The vast difference in value between DEC and DEP is primarily due to differences in the timing of assumed capacity need. For DEC there is no capacity value assumed from 2020 through 2026 since Duke projects no capacity need until 2026. In contrast, DEP projects a capacity need as early as 2020, and thus ascribes an avoided capacity value from 2020 through 2029.

iii. *Timing of Capacity Value*

Q. How is Duke's proposal biased in terms of the timing of capacity value provided by a QF facility?

A. Duke's proposal underestimated capacity value in two ways related to timing: 1) For DEC, Duke inappropriately assumes that each QF provides zero capacity value from 2020 through 2026, which is the year it has determined there to be a capacity need. 2) Additionally, Duke assumes that each QF provides zero capacity value after 2029.

Q. Why is inappropriate to assume that there is no capacity value until 2026 for DEC?

A. While it is true that Duke's load and resource forecast do not project an internal resource need until 2026, this does not mean that there is no capacity value during this interim period. In fact, Duke regularly engages in both bilateral sales and purchases of both energy and capacity with other load serving entities in the region.

Q. Can you describe how Duke engages in wholesale capacity sales?

A. Yes. In its 2019 IRP, DEC projects over 1,600 MW in wholesale sales contracts in each year from 2019 through 2028.[41] While many of Duke's firm sales contracts are for both capacity and energy, Duke has engaged in sales of capacity only contracts as recently as [redacted]. According to Duke's response to SBA Int 2-6, the value of these capacity only contracts was [redacted].[42]

Furthermore, Duke's system has interties with the PJM wholesale market. Thus, it is conceivable that Duke could offer its excess capacity resources into PJM's capacity market (the Reliability Pricing Model) and receive corresponding compensation. In any case, Duke has the option to sell its excess capacity at the wholesale level and receive commensurate compensation for doing so. This compensation can in turn be used to help offset overall generation costs, and provide a benefit (i.e. an avoided cost) to its retail customers. The addition of QF

[41] DEC 2019 IRP Update Report, Table 13-A

[42] [redacted]

capacity would further increase Duke's capacity position, allowing for greater off-system capacity sales.

Q. Can you describe how Duke engages in wholesale capacity purchases?

A. Yes. According to Duke's response to ORS 2-17a, Duke is engaged in the purchase of capacity from multiple resources from January 2019 through December 2029. The total amount of capacity purchased ranges from [redacted] in any given month over this period. Although, the price of the purchases varies, there is at least one long-term contract through 2029 that has an average purchase price of [redacted]. The addition of QF capacity would further increase Duke's capacity position, allowing for a reduced need for short-term capacity purchases, thereby potentially offsetting these costs going forward. As such Duke should compensate QFs for these avoided capacity cost in the form of payment through avoided capacity rates.

Q. Is there precedent for including these types of short-term market capacity values in avoided cost calculations?

A. Yes. Until recently, California used an approach whereby avoided cost estimations included a near-term avoided capacity value based on the prices of the state's bilateral capacity market (also known as the Resource Adequacy market).[43] This method reflected the appropriate capacity value distributed resources provided to ratepayers by avoiding the need to contract for capacity through bilateral trades prior to the year of new resource needs. More recently, the state has assumed an approach that assumes full capacity value of a new resource in the current year regardless of the year of resource need.

Q. Is it possible to estimate the effects such an evaluation of market capacity value would have on avoided costs?

Yes. A viable proxy for the market value of capacity is the clearing prices in PJM's capacity market, called the Reliability Pricing Model (RPM). According to PJM, the clearing price in their last Base Residual Auction (BRA) was $140/MW-day (or about $51/kW-yr). In their 2018 IRP, Dominion Energy Virginia includes estimates for the RTO-wide clearing prices for delivery over the following 15 years.[44] This data shows that the potential market valuation of each kW of capacity provided escalates from $31.5 in 2020 to $50.62 in 2025. Using this information, it is possible to estimate the effects an evaluation of market prices would have on the avoided capacity costs.

[43] "Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework D. 16-06-007", California Public Utilities Commission, 2016, pp. 12-13.
[44] Dominion Energy Virginia 2018 Integrated Resource Plan, Appendix 4A: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf

Q. Do you have any recommendations for avoided capacity costs for DEC in years 2020 through 2026?

A. Yes. While the capacity provided by the QF in this period may not be necessary to cover any internal capacity deficiencies, it may still traded by DEC either bilaterally or into PJM's RPM and subsequently credited to Duke customers. A consideration of an adequate proxy of the value of said capacity, such as the clearing prices in PJM's RPM, would yield a reasonable assessment of the avoided cost provided by such capacity. I believe this component is fundamental in the avoided capacity cost calculation performed by DEC in the 2020-2026 period; by omitting such potential, Duke is depressing the avoided cost thus hindering the valuation of QFs.

Q. Why is it inappropriate to assume that there is no capacity value from QFs past 2029?

A. New generation resources, like gas peakers, typically have a project life of 30 years or more. Thus, the benefit to ratepayers of avoided capacity from QFs may extend well beyond the life of the proposed 10-year contract period. While it is true that Duke's proposal would limit the capacity component of QF contracts to 10 years, most solar PV resources have a project lifetime of 20 years or more.

Hence, there is a significant likelihood that the capacity from these projects could be re-contracted at a later date. Since there would be no fuel costs, no fuel transport costs, and minimal O&M, the cost to recontract for capacity would likely be very low compared to other options. This provides a meaningful “option value” versus building new generation in the 2029 timeframe.

Q. Do you recommend adjusting Duke’s avoided cost methodology to reflect this option value?

A. Not at this time, however it could be considered in future avoided cost proceedings. Additionally, it is another reason why the Commission should lean towards the side of higher QF rates within the zone of reasonableness.

B. Alternative AC Capacity Rate Proposal

Q. Given the deficiencies in Duke’s proposal, what do you recommend instead?

A. I propose a revised calculation of the avoided capacity rate proposed by Duke. This revision corrects for many of the deficiencies described above. More specifically it includes:

- Adjustments to the seasonal allocation.

- An updated peaker capital cost assumption that reflects: 1) a different generator type that better reflects recent trends, 2) reduced economies of scale that better reflects the likely buildout of a new peaker plant, and 3) inclusion of additional transmission upgrades.
- Inclusion of capacity value prior to 2026 for DEC.

[redacted]

[redacted]

[redacted]

Q. Would you be open to further revisions of this alternative calculation?

A. Yes. In fact, I intend to revise the calculation based upon pending information requests to Duke that have not yet been provided.

VII. <u>INTEGRATION SERVICES CHARGE</u>

Q. Have you reviewed Duke testimony regarding its proposed Integration Services Charge (ISC) for solar QFs?

A. Yes.

Q. Do you have concerns regarding Duke's proposed ISC and supporting analysis?

A. Yes, I have several concerns including the following:

1) I believe it is premature to impose an ISC on solar QFs until the true costs of integration can be more accurately quantified through an *independent* analysis as contemplated by Act 62.
2) The analytical model Duke uses to support the proposed ISC contains several fundamental flaws that likely exaggerate the projected cost of integration services.
3) There is very little evidence in South Carolina, or in other jurisdictions, that the magnitude of integration costs projected by Duke will materialize soon due to incremental solar deployment.
4) Duke's proposal is incomplete since it only considers integration costs imposed by solar QFs and does not consider integration services that could be provided by solar QFs (as required by Act 62).
5) The form of the proposed ISC is linked to a hypothetical model rather than real-world costs and introduces unnecessary uncertainty that would stymie solar QF project development.

I will explain each of these in more detail in my testimony below.

A. <u>ISC is Premature</u>

Q. Please explain why you believe it is premature to impose an ISC now.

A. Upon passage of Act 62, South Carolina statute was amended to include the following language authorizing ORS to conduct an independent study on integration services:

> "Section 58 37 60. (A) The commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest. Studies shall be based on the balancing areas of each electrical utility. The commission shall provide an opportunity for interested parties to provide input on the appropriate scope of the study and also to provide comments on a draft report before it is finalized. All data and information relied on by the independent consultant in preparation of the draft study shall be made available to interested parties, subject to appropriate confidentiality protections, during the public comment period. The results of the independent study shall be reported to the General Assembly.
>
> (B) The commission may require regular updates from utilities regarding the implementation of the state's renewable energy policies.
>
> (C) The commission may hire or retain a consultant to assist with the independent study authorized by this section. The commission is exempt from complying with the State Procurement Code in the selection and hiring of the consultant authorized by this subsection."

I believe the process laid out in this statue is sound and would provide a transparent and independent approach to determining the true integration needs and related costs for South Carolina utilities. In contrast, the integration study performed by Duke in this proceeding did not include "an opportunity for interested parties to provide input on the appropriate scope of the study" nor did it provide for "comments on a draft report before it is finalized." Thus, rather than rely solely on a study commissioned by Duke with no peer review or input from outside stakeholders in this proceeding, I believe the process defined by Act 62 better serves the public interest and would be more appropriate for investigating whether an ISC is necessary and what the magnitude of such a charge should be.

Q. What is your recommendation for the ISC in this proceeding?

A. I recommend that the PSC consider whether an ISC is warranted, and determine the level of the ISC (if any), *only after* ORS' independent study is completed, as outlined by Act 62.

B. Flaws in Analytical Model

Q. Please explain why you believe the analytical model Duke used to support the proposed ISC is flawed.

A. Duke relied upon the Solar Ancillary Services Study conducted by Astrape Consulting to determine its proposed integration charge. There are a variety of reasons to believe the model used in this study and underlying assumptions are not appropriate for determining integration costs, including the following:

1) The proposed LOLE-flex metric of 0.1/year used to determine minimum ancillary service requirements is too stringent and does not accurately reflect how the power system is actually operated today under the applicable NERC standards.
2) The model inappropriately treats Duke's balancing areas as islanded systems, which leads to a significant overestimation of integration costs.
3) The modeled solar output profile overestimates volatility and fails to account for the effects of geographic diversity, thus inherently overestimating integration costs.
4) The model used to determine integration costs appears to be different than the model used to determine avoided energy costs. If the two were not co-optimized, this may lead to a double counting problem that either overestimates integration costs or underestimates avoided energy costs.
5) The unit commitment and dispatch procedures modeled in the ancillary services study may not match Duke's actual practices and may tend to overestimate integration costs.

i. *<u>LOLE-flex metric</u>*

Q. Please explain why the LOLE-flex metric of 0.1/year used by Duke is too stringent and does not reflect reality.

A. The 0.1/yr LOLE-flex metric used in the Ancillary Services study suggests that an imbalance between generation and load lasting 5 minutes or more can only be tolerated once every 10 years. In Duke's own words, "LOLE-FLEX essentially requires the system to maintain enough ramping capability to match 5-minute load ramps in all but one period every 10 years"[45] In reality, Duke's power system is part of a larger interconnection with many other participants that allows for significant deviation between generation and load on a five minute basis. In fact, this has been a frequent occurrence for Duke in recent years and it has often sustained a large imbalance between generation and load over a five-minute periods.

Q. Do you have any evidence of how the imbalance between generation and load on Duke's system regularly deviates on a 5-minute basis?

A. Yes. In fact, the metric for detecting such an imbalance within a control area (e.g. DEC, DEP-West, DEP-East) is commonly known as Area Control Error or ACE. In 2018, the ACE for DEP-East was as large as -1005 MW over a five-minute period, meaning that it was under-generating by this amount and needed to ramp up an equivalent level.[46] Even in 2015, prior to significant solar

[45] NCUC Docket No. E-100, Sub 158, Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, March 27, 2019.
[46] Based on DEP OASIS data

deployment, the ACE was as large as –673 MW on a five-minute basis. This far exceeds the 26 MW of load following reserve additions that Duke's study claims will be required for solar integration and are a driver of related integration costs. As shown in the figure below for 2015, the 5-minute imbalance for DEP regularly deviates between +/- 200 MW and sometimes is even greater.

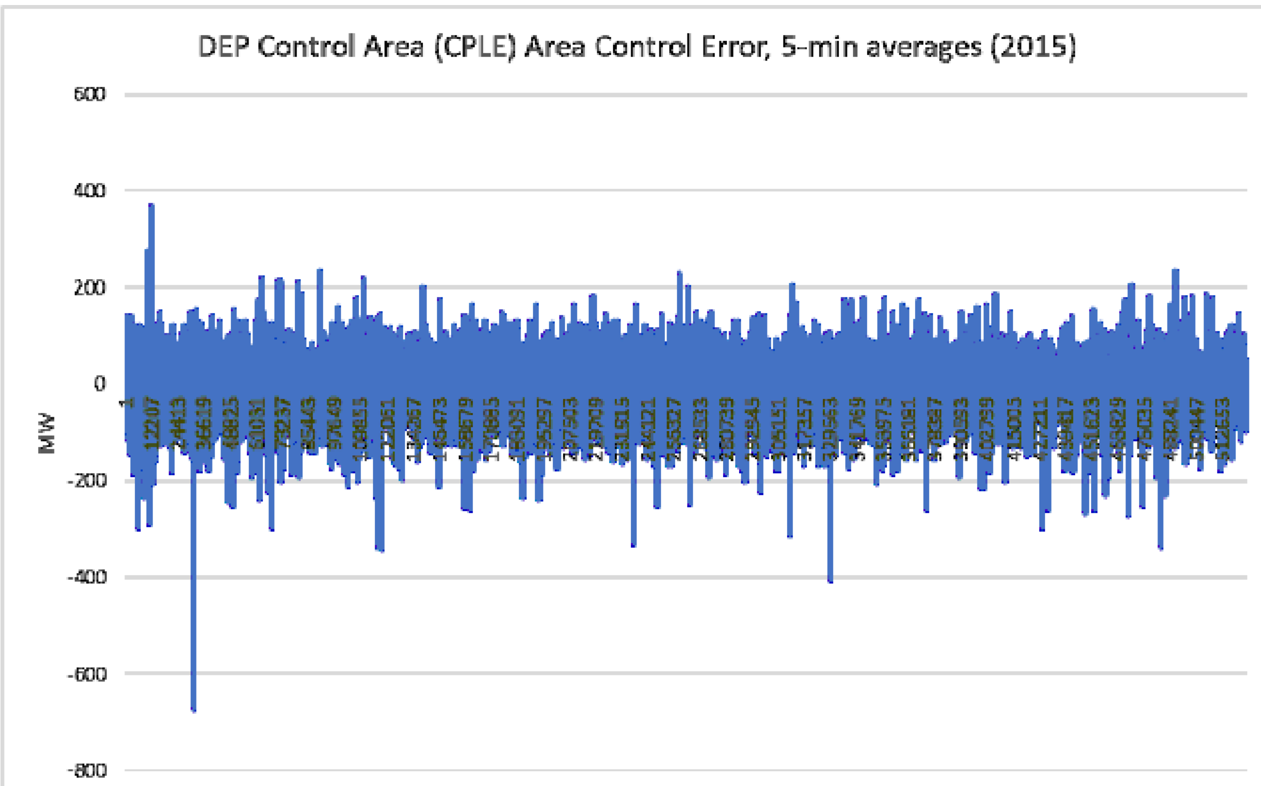


Figure 5. Area Control Error (ACE) for Duke's DEP-East System in 2015

Deviations of the amount depicted above are not necessarily a serious reliability concern and, to my knowledge, there is no NERC standard that approaches a requirement for Duke to maintain a 0.1/year LOLE-flex.

Q. What has Duke said about the relevance of the LOLE-flex metric to its current operations with respect to compliance with NERC Balancing Standards?

A. To my knowledge, there is no connection between LOLE-flex and any applicable NERC standards. I am still awaiting more information from Duke on this issue.

ii. *Islanded systems*

Q. What are your concerns regarding the Ancillary Service Study's treatment of the DEP and DEC systems as islanded systems?

A. My concern is that this is not a true reflection of how Duke's system truly operates. In reality, there is constant interaction between Duke's balancing areas and those surrounding it simply as a function of being interconnected to a larger system. As a simple illustrative example, the figure below how over a recent 2-day period Duke engaged in interchanges with its neighbors ranging from almost 1,500 MW in exports to almost 1,000 MW in imports.[47]

[47] https://www.eia.gov/realtime_grid/?src=data#/data/graphs?end=20190827T00&start=20190820T00&dataTypes=0g&bas=0000002&regions=0

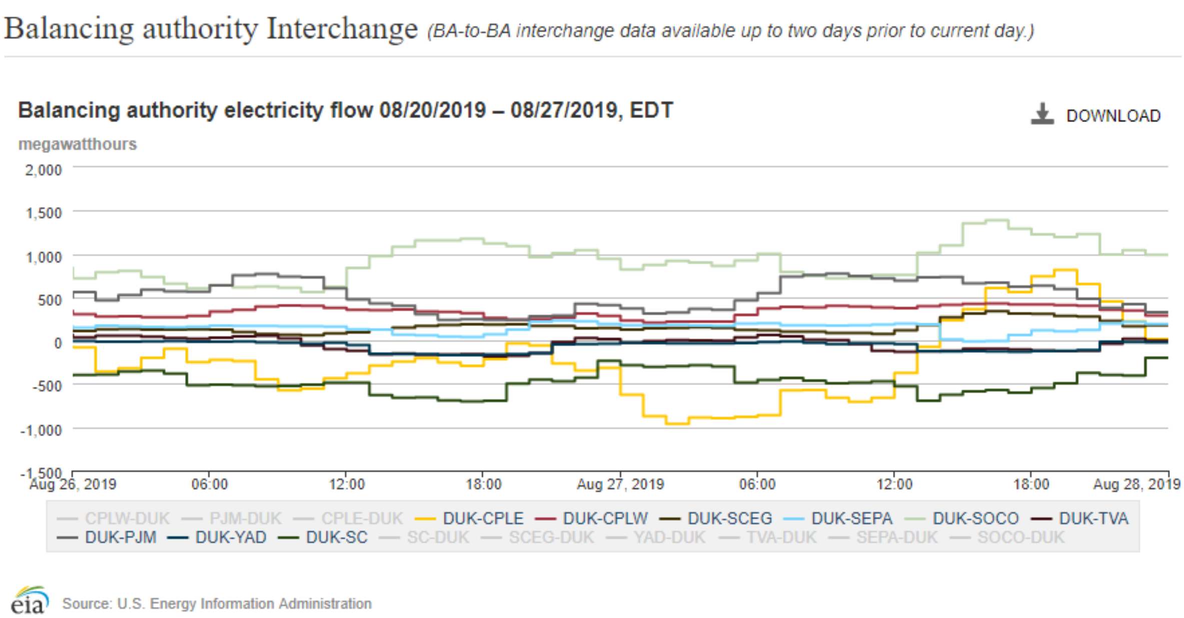


Figure 6. Interchange between Duke and neighboring areas over a two-day period

While system operators can "schedule" point to point transactions through contractual arrangements, electricity flows based on the laws of physics (not contracts) and there is frequently unscheduled flow back and forth between different areas. Stability on the grid is maintained by each operator responding in real time to maintain the overall balance of the grid's frequency when there is an imbalance.

Q. What are the implications of underestimating these interactions in terms of integration costs?

A. The implications are significant. For example, Duke recently performed a sensitivity analysis for the North Carolina Utilities Commission on its integration study (the same study submitted in this proceeding) wherein the operation of its two balancing areas (DEP and DEC) was assumed to be combined rather than islanded.[48] The results showed a 15% decrease in ancillary service costs (i.e. integration costs). These results were reproduced in Duke's response to SBA RFP 2-8 in this proceeding.

Q. Do you agree with Duke's characterization of this change as "modest" or insignificant?

A. No. This is a significant change that stems from modeling the interaction of just two balancing authorities (i.e. DEP and DEC) as already occurs in real-world operations. In reality, there are even more balancing authorities that Duke interacts with throughout the Eastern Interconnection. If all of these were appropriately modeled to reflect their interactive effects, I believe the ancillary service cost impacts would be even lower.

iii. <u>Volatility Profile</u>

Q. What are your concerns regarding the Ancillary Services Study's treatment of volatility in solar output?

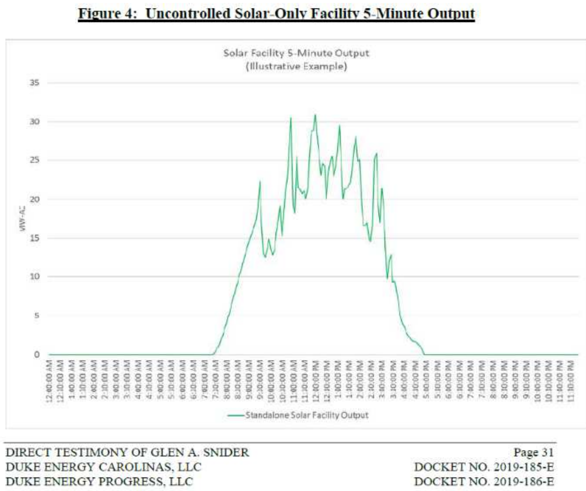
[48] Direct Testimony of Nick Wintermantel, NCUC Docket No. E-100, Sub 158.

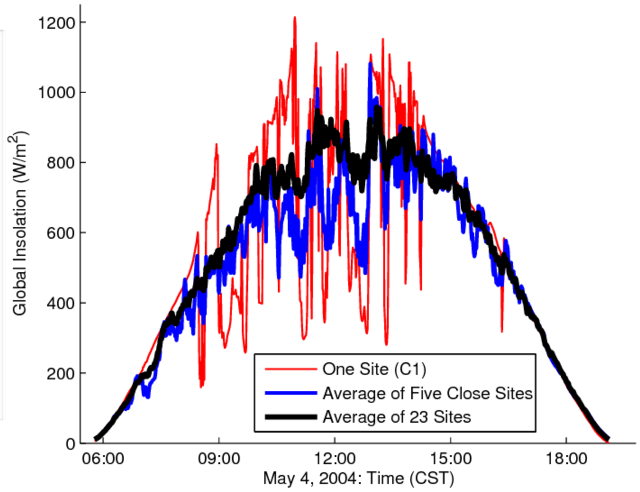
A. My main concern is that the model inappropriately scales the solar output profile linearly for higher penetration levels. This incorrectly exacerbates the volatility profile and fails to account for the mitigating effect of geographic diversity.

Q. What do you mean by geographic diversity?

A. This means that the minute-to-minute variability of solar output (e.g. from clouds) typically is not replicated across many solar PV locations. Thus, if a single PV output profile, or even a small number of output profiles is used to characterize a larger deployment of solar, it may inadvertently overstate the amount of variability experienced by utility system operators. As an example, the figure below shows two charts. The chart on the left is excerpted from Duke's testimony and shows a solar profile with significant variability on a 5-minute basis. However, this is not actually representative of what a fleet of solar resources will provide. The chart on the right illustrates this principle.[49] Notably the aggregation of 23 sites shows significantly reduced variability when compared to a single site or the average of five sites. This is due to the fact that environmental factors like clouds are usually uncorrelated across wider geographic areas. Thus, the variability and related ancillary service costs for solar are reduced over a larger scale.

[49] https://ieeexplore.ieee.org/document/6039888





Q. How does Duke's study treat this minute-to-minute variability in solar output?

A. Duke includes a "volatility profile" to simulate this variability. However, the approach is flawed. The study scales up the variability in a linear fashion, as if ~~the~~all future solar output ~~all~~ occurred in ~~the exact same location~~fixed locations. If the profiles were distributed across a broader geography (as is likely to occur in reality), the volatility would be greatly reduced.

Q. What are the implications of this in terms of integration costs?

A. Duke has modeled at least one scenario with a reduced solar volatility profile (i.e. The 75% Solar Volatility Assumption). In DEC's case this yielded an integration cost that was over 70% lower than the comparable case without a volatility reduction.

C. Lack of Observed Integration Costs to Date

Q. What are the main drivers of integration costs according to Duke's study?

A. According to Duke's study, increased amount of solar leads to an increased need to hold operating reserves – in particular, load-following reserves – which increases overall operating costs. What this means is that system operators must have generators online and ready to ramp up or down if there is a fluctuation in solar generation. This can incur some cost due to the need to turn on the load-following units.

Q. Is there any strong evidence that increased operating reserves have been required in the Carolinas as a result of increased solar deployment?

A. No. In fact, this issue recently came up in North Carolina's avoided cost proceeding. More specifically, Duke provided evidence that the amount of operating reserves required in 2018 have increased by about 3% from 2015 levels.[50] This stable level of operating reserves is true despite a 409% increase

[50] This information was reproduced in Duke's response to ORS 2-9.

in solar generation in North Carolina over the same period (see table below).[51] Additionally, the amount of operating reserves actually decreases in years 2016 and 2017 (from 2015 levels) despite increasing levels of solar.

Year	DEC/DEP Average Annual Actual Realized 60 Minute Ramping Capability in MW		NC solar generation (GWh, Million kWh)	
2015	1833	-	1374	-
2016	1665	-9%	3421	+149%
2017	1595	-13%	5579	+306%
2018	1887	+3%	6997	+409%

Q. What are the potential drivers of these changes in operating reserves other than solar?

A. As Duke stated in its filing to the NCUC, "Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar."[52] Thus solar is just one of many factors that may contribute to the overall need for ancillary service costs.

[51] Energy Information Administration (EIA)"[6] Table 1.17B Net Generation from Solar by state by sector

[52] This information was reproduced in Duke's response to ORS 2-9.

Q. What do you conclude from this observation?

A. There are a variety of factors that could potentially drive ancillary services and/or “integration costs” that are unrelated to incremental solar. Many of these are related simply to the existing characteristics of the utility system and others are related to the decisions and practices of its operators. As such, it is unreasonable to attribute all future incremental load following reserves (i.e. “integration costs”) to solar. Such an attribution would violate the principle of cost causation.

Q. What has been the experience in other regions in terms of integration costs related to solar?

A. In general, the need for ancillary services has remained relatively static in many markets despite significant increases in renewable energy generation such as solar. As an example, the California Independent System Operator (CAISO) routinely reports on the amount of ancillary services it procures, as well as the overall generation mix. From 2011 through 2018 (the most recent annual market report), the amount of ancillary services procured in the form of regulating reserves has not significantly increased, despite the amount of renewable energy increasing from 9% to 26%. This is illustrated in the chart below.

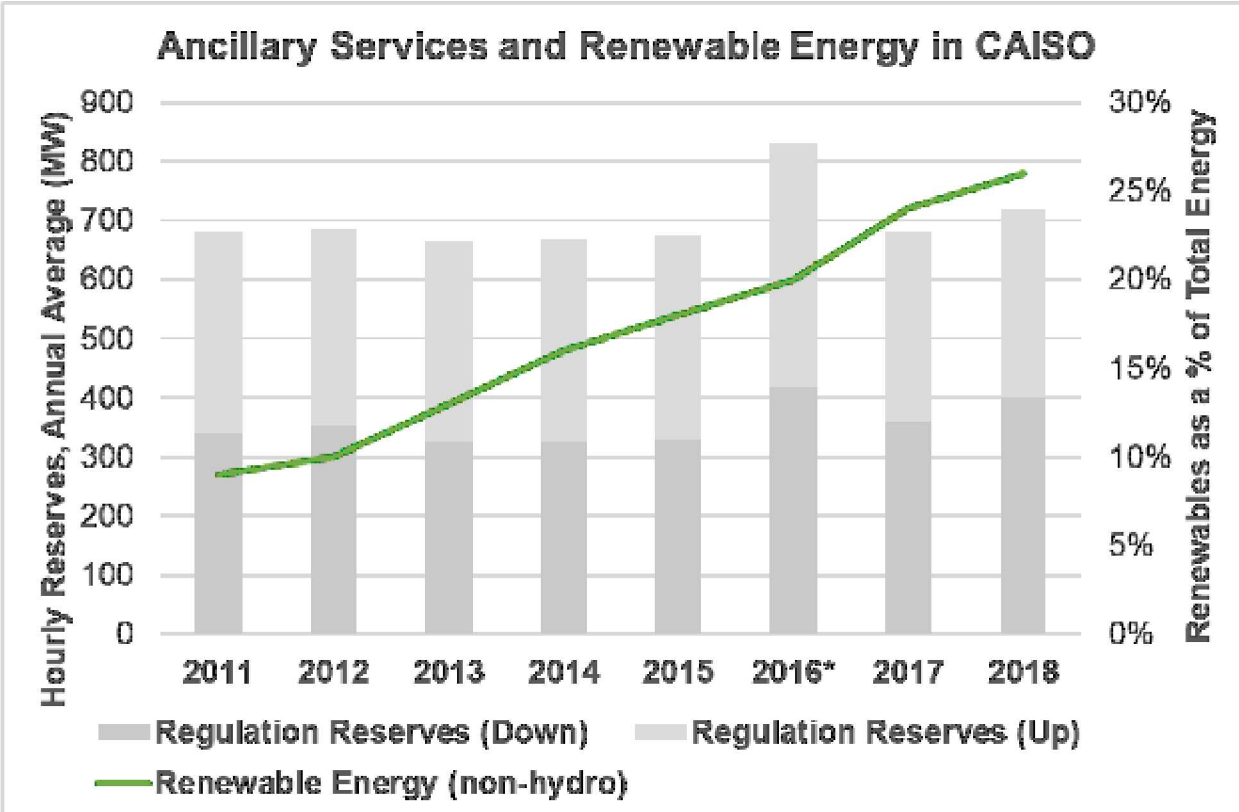


*Figure 7. Trends in ancillary service requirements and renewable energy for the California Independent System Operator. *2016 requirements described in testimony below.*

One exception to this was during the spring of 2016. The CAISO anticipated a greater need for ancillary services, in part due to increased penetration of renewable energy. However, in the fall of the same year, the CAISO implemented a new methodology for determining how much ancillary services were truly needed, and the requirement fell in subsequent years.

Q. Are there steps that utilities such as Duke could take to minimize integration costs, thereby reducing costs to their customers?

A. Yes, there are many. To name a few:

- Duke could participate in a regional energy imbalance market. This has proven to be a significant benefit to utilities and their customers in the

Western Interconnection, and also helps to address the costs of integrating variable renewable energy resources.

- Duke could enhance its renewable energy resource forecasting procedures. More accurate forecasting enables more efficient unit commitment and dispatch processes, thereby reducing the need for operating reserves and associated costs.
- Duke could improve the flexibility of its baseload resources. Inflexible resources are often a big driver of integration costs as renewables are added. Retrofits or operational enhancements to improve the flexibility of baseload units could help unlock these benefits for Duke's customers.

D. <u>Lack of Symmetric Compensation</u>

Q. Why do you believe that Duke's proposed approach to integration services is incomplete?

A. While Duke has addressed the possible increase in ancillary service needs due to incremental solar, it has failed to address the fact that solar can also provide ancillary services, thereby reducing overall costs to customers. Act 62 specifically requires that avoided cost calculations account for the value of ancillary services produced, as well as consumed, by QFs.

Q. Many people think of renewable resources like solar as requiring additional ancillary services to help balance their variability. Is it true that renewables can actually provide ancillary services themselves?

A. Absolutely. In fact, recent demonstrations in the CAISO have illustrated that renewable resources can actually be better at providing these services than conventional resources. The chart below provides demonstration of this in terms of a recent solar project providing regulation services more accurately than conventional resources.

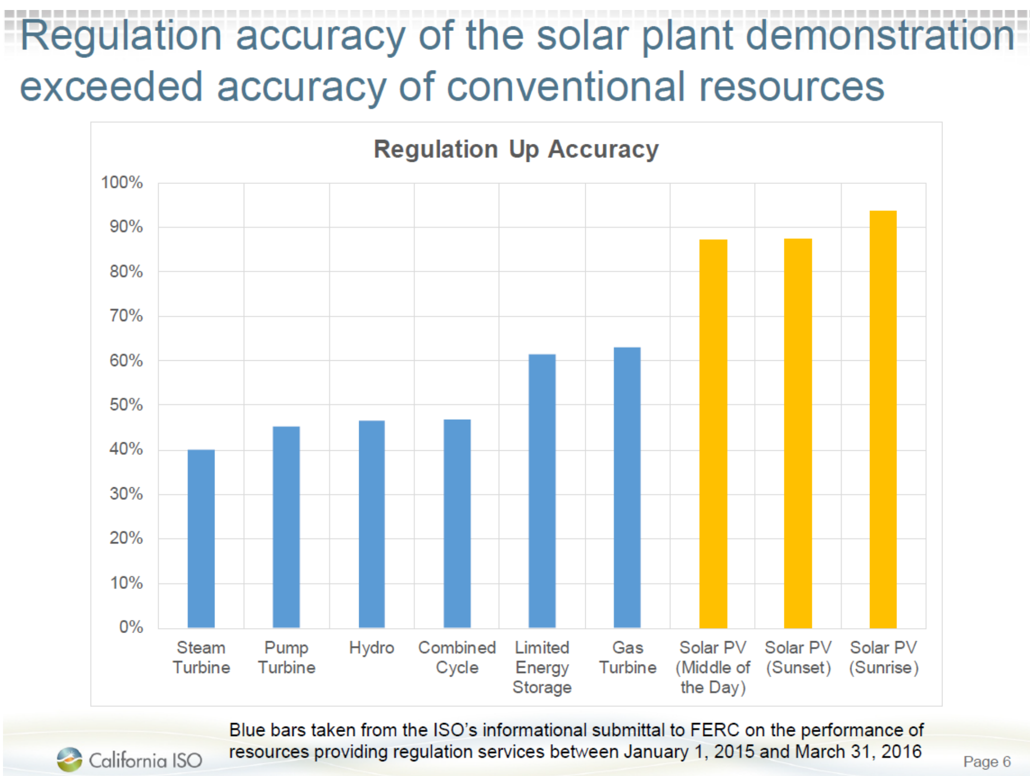


Figure 8. Ancillary services provided by the CAISO/First Solar/NREL demonstration project[53]

Q. What other methods are there for inverter-based resources (like solar) to provide ancillary services?

A. While there are many options (including simply using the capabilities of modern inverter technologies) energy storage provides additional capabilities in this regard.

Q. If QFs can provide ancillary services, how should such services be priced?

A. Under existing law, Duke provides an Open Access Transmission Tariff (OATT) that provides published schedules for many of the ancillary services it offers.[54] This could be starting point for any ancillary services provided by QFs under a PURPA contract.

[53] https://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf

[54] DEC OATT: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20180515-5328
DEP OATT: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20180515-5329

E. Form of Proposed ISC and Alternative Integration Charge Computation

Q. Given the shortcomings you have outlined regarding Duke's proposed ISC, what do you recommend instead?

A. First and foremost, I recommend that the Commission reject considering any ISC until the independent integration study authorized by Act 62 is completed. The reason for rejecting this charge are due to the fact that:

- It is premature to impose an ISC on solar QFs until an independent analysis as contemplated by Act 62.
- The analytical model Duke uses to support the proposed ISC contains several fundamental flaws including, an overly restrictive LOLE-flex metric, inappropriate assumptions regarding islanded systems, and an inaccurate volatility profile (among other things).
- There is very little evidence from other regions that significant integration costs will materialize.
- Duke's proposal does not consider integration services that could be provided by solar QFs.

However, if the Commission feels compelled to adopt some sort of integration charge prior to the completion of that study, I have several recommendations for how such a charge should be implemented.

Q. What are your recommendations if the Commission does feel compelled to approve an integration charge?

A. Any integration charge should include the following features:

1. The charge should be adequately capped to ensure QF developers are not subjected to unlimited risk.
2. The level of the cap should reflect the true drivers of integration costs which are not solely attributable to solar QF resources.
3. The actual level of the charge should be based on real-world data rather than modeled projections.
4. The integration charge should be able to be mitigated through appropriate dispatch of solar, storage, or other QF technologies.

Q. Can you please describe each of these features in greater detail?

A. Yes. I've addressed each of these in my testimony below.

i. *<u>Cap on Integration Charges</u>*

Q. Does Duke's proposal allow the integration charge to increase over time?

A. Yes. As stated in Mr. Snider's Direct Testimony at page 36, "The Integration Services Charge within a solar provider's contract will be updated biennially at each avoided cost proceeding. This will allow for the uniform application of the charge and will account for changes in market factors impacting the cost of integration over time."

Q. Has Duke proposed a cap on an integration charge imposed on solar facilities?

A. Yes, Duke has proposed a cap of $3.22/MWh for DEC and $6.70/MWh for DEP, which represents a 292% increase of the proposed integration charge in DEC and 280% increase of the proposed charge in DEP.

Q. What does this mean from a QF project developer's standpoint?

A. Since the integration charge could change over time, essentially this means that all QF projects will have to assume that they will be required to pay the full capped rate during the PPA. This will increase project costs despite the fact that real-world examples indicate that any integration costs are likely to remain flat or even decrease over time rather than increase. Further, the variable nature of the charge and the high level of the proposed cap will subject the project owner to uncertainty with respect to project revenue. This means that it will be difficult if not impossible for QF developers to obtain financing for new QF projects. This could lead to the unintended consequence of halting all future QF projects.

Q. What remedy might be able to resolve this?

A. If an integration charge is imposed, it is necessary (and fair) to include a reasonable cap that limits the integration charge for projects of a similar vintage to a reasonable level.

ii. Level of Cap

Q. What method would you propose for setting the initial level of the cap on integration charges if one is approved in this proceeding?

A. Duke has proposed integration charges of $1.10/MWh for DEC and $2.39/MWh for DEP. This could be useful as a starting point, however, as explained above, there are a variety of shortcomings in the way these charges were estimated that need to be corrected for.

Q. How would you recommend making these corrections?

A. Ideally this would be one of the outcomes of any independent integration cost study as described earlier in my testimony. However, if one assumes Duke's proposed charges as a starting point, I would suggest the following potential modifications using DEP as an illustrative example:[55]

[55] The table shown is intended to be an illustrative example. Strategen recognizes that there are potential interactive effects of several of these changes. Additionally, certain values were included as placeholders since additional analysis is necessary to determine more precise estimates. This is intended to highlight the numerous mitigating factors that would tend to reduce integration costs and would need to be accounted for before an integration cost cap can be set.

Modification	% Change	Resulting Integration Charge Cap ($/MWh)	Rationale
Duke's initial proposed integration services charge for DEP	--	$2.39	Based on Astrape Ancillary Services Study
Relaxed LOLE-flex requirement	-2%	$2.34	Based on Duke's response to SBA RFP 2-8 assuming 1.0 LOLE-flex.[56]
Reduced volatility profile due to geographic diversity	-35%	$1.52	Based on comparing Duke's "+1500" and "+1500, 75% Volatility" scenarios.
Operating reserve changes during solar hours only (versus all 8760 hours)	-52%	$0.73	Approximated based on hours with no solar production (assumes SAT).
Non-islanded operation (DEC & DEP only)	-15%	$0.62	Based on Duke's analysis provided in SBA RfP 2-8
Non-islanded operation (rest of Eastern Interconnection)	-15%	$0.53	Strategen placeholder estimate (further study is needed to accurately determine).
Improvements in solar forecasting practices (not attributable to QFs)	-1%	$0.52	Strategen placeholder estimate (further study is needed to accurately determine)
Improvements in intra-hour dispatch, including regionally coordinated imbalance services (not attributable to QFs)	-1%	$0.52	Strategen placeholder estimate (further study is needed to accurately determine).

[56] Note that Strategen still considers this to be a very stringent requirement relative to NERC balancing standards

iii. *Actual Integration Costs*

Q. Beyond setting the level of the cap, how do you recommend setting the actual value of the integration charge?

A. I recommend that the actual integration charge (if one is approved by this Commission) be based upon actual real-world data regarding Duke's operating reserves coincident with QF production. For example, an annual review could be conducted to determine how many MW of spinning reserves Duke committed in each hour of the year that coincided with solar QF production. A determination could be made as to whether this level of reserves was higher or lower than in previous years. If higher, then a further determination could be made as to what portion of those reserves, and associated costs, might have been attributable to solar QFs.

Q. What caution must be taken in making this determination?

A. As Duke has stated, "Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar."[57] Thus, care must be taken to isolate the operating reserve changes that are attributable to solar

[57] See Duke's response to ORS 2-9.

versus other factors. Additionally, further care must be taken to isolate the fraction of these solar-related costs that are due to QFs versus other renewable resources on Duke's systems.

iv. *Dispatchable solar QFs*

Q. What special considerations should be given to solar QFs that are dispatchable?

A. As explained in my testimony above, modern inverter-based resources such as solar PV or solar PV coupled with battery storage are dispatchable resources. Like any grid resource, there are certain limitations (for example, a solar-only resource may need to pre-curtail to provide upward ramping capability), however there is a broad range of functionality that these resources can provide. These could include frequency regulation, load following, frequency response, voltage control, strategic curtailment (during constrained periods), and so on. These functionalities could be provided as a means to enhance value to the grid and in turn reduce costs to Duke's customers. If these QFs are able to provide these services I believe they should also be provided commensurate compensation. As one example, if a solar QF can reduce the variability of its output, or even offer load-following services, a reduction/elimination of integration charges would be warranted. In another case, if QFs are able to curtail during periods of negative avoided costs, they should be awarded a premium avoided energy cost rate during other hours.

Q. Do you have any recommendations for how to treat dispatchable QFs in this proceeding?

A. While there is great potential to harness the capabilities of dispatchable solar for the benefit of customers, I recognize that there are also many complexities involved. As such, recommend that the PSC direct the parties to convene a working group to develop a PPA structure which would support these features.

Q. Does this conclude your testimony?

A. Yes.

VIII. **EXHIBIT ______**

Ed Burgess Full Resume

Edward Burgess
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941-266-0017

Overview

Ed Burgess is Senior Director of Strategen Consulting's Government and Utility Consulting Practice. His core expertise is in policy and regulation of the electric power sector at the state level, with a specialized focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design. Ed has served clients in the renewable energy, energy storage, electric vehicle, and energy efficiency industries, including several private companies, energy project developers, trade associations, utilities, government agencies, and foundations. His technical analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed energy resources, rate design, resource planning and transmission/distribution system planning. Prior to joining Strategen, Ed played a lead role in two major initiatives at Arizona State University: The Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona. Ed also worked as an independent consultant for Schlegel & Associates, providing technical analysis on demand-side management policies, and for Kris Mayes Law Firm providing regulatory support to the solar industry in the Southwest U.S.

Senior Director
AUG 2019 – Present
Director
JAN 2018 – AUG 2019
Senior Manager
JUL 2016 – DEC 2017
Manager
JUL 2015 – JUN 2016
Strategen Consulting – Berkeley, CA

Independent Consultant
NOV 2012 – JUL 2015
Schlegel & Associates – Phoenix, AZ
JUN 2012 – JUL 2015

EDUCATION

PSM, Solar Energy Engineering and Commercialization
Arizona State University, 2012

MS, Sustainability
Arizona State University, 2011

BA, Chemistry
Princeton University, 2007

EXPERIENCE – 11 YEARS

Energy Resource Planning & Procurement

Utility Rates and Regulation

Cost Benefit Analysis

Avoided Cost and Cost Effectiveness

Energy Policy & Markets

Energy Product Development & Market Strategy

Stakeholder Engagement

Management Consulting

Kris Mayes Law Firm – Phoenix, AZ

Project Manager & Researcher
JUN 2012 – JUL 2015
Arizona State University – Tempe, AZ

Instructor
JUN 2011 – MAY 2012
Arizona State University School of Sustainability – Tempe, AZ

Research Fellow
JUL 2007 – JUL 2009
Environmental Defense Fund – New York, NY

EXPERT TESTIMONY

National Grid, Electric Vehicle Infrastructure Program, Docket No 18-150

Selection of Relevant Projects at Strategen Consulting

Massachusetts Attorney General's Office

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of the Consumer Advocate

- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources.
- Developed a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

District of Columbia, Office of the People's Counsel

- Provided technical support and analysis on a utility proposed electric vehicle charging program
- Supported drafting comments on the Counsel's position in favor of a more customer-friendly approach to electric vehicle program implementation

North Carolina, Office of the Attorney General

- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.

Maryland, Office of People's Counsel

- Provided technical support to the state's consumer advocate topics associated with the large PC44 grid modernization effort.
- Topics included electric vehicles, energy storage, distribution grid planning, and interconnection.

Arizona, Residential Utility Consumer Office (RUCO)

- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.

- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Portland General Electric

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for potential storage technology solution providers.

Xcel Energy

- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

City and County of San Francisco

- Aided in evaluation of solar PV with battery storage as a solution for resilience of critical infrastructure.
- Provided technical economic assessment of opportunities for wholesale market participation as an added value for facilities installed.

University of California, San Diego

- Conducted economic analysis to help guide a multi-year research project on the use of advanced solar forecasting technology to improve integrated solar and energy storage.

University of Minnesota

- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

Arizona State University (ASU)/Arizona Department of Environmental Quality (ADEQ)

- Project manager for partnership between ASU/ADEQ to study compliance options for the state of Arizona to meet requirements of the EPA's Clean Power Plan (CPP).

- Completed a comprehensive study on the impact of CPP scenarios on the operation of the southwest power grid and cost to Arizona and Navajo Nation electricity customers.

Recent Publications

- Edward Burgess, Ellen Zuckerman, and Jeff Schlegel, “Is the Duck Curve Eroding the Value of Energy Efficiency” Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2018 Summer Study on Energy Efficiency in Buildings, (pending).
- Lon Huber, Ed Burgess, “Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future,” (November 2016), Arizona Residential Utility Consumer Office, Arizona Corporation Commission, Docket No. E-00000Q-16-0289, https://www.strategen.com/s/Evolving-the-RPS-Whitepaper.pdf
- Mark Higgins, Ed Burgess, and Bill Ehrlich, “Energy Storage Likely to Increase in Utility Resource Planning” Natural Gas and Electricity, Volume 32, Number 10 (May 2016).
- Ellen Zuckerman, Edward Burgess, and Jeff Schlegel, “Are Recent Forays into Restructuring a Threat to Energy Efficiency?” Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2014 Summer Study on Energy Efficiency in Buildings, (August 2014) http://aceee.org/files/proceedings/2014/data/papers/6-1135.pdf#page=1.
- Sonia Aggarwal and Edward Burgess, “Performance Based Models to Address Regulatory Challenges” The Electricity Journal (July 2014) http://www.sciencedirect.com/science/article/pii/S1040619014001389.
- “Transmission and Renewable Energy Planning in California,” prepared for the Western Governors Association, (November 2012) http://www.westgov.org/wieb/wrez/11-28-2012WREZca.pdf.
- Edward Burgess and Petra Todorovich, “High-Speed Rail and Reducing Oil Dependence” in Transport Beyond Oil, Island Press (March 2013).
- “On the nature of the dirty ice at the bottom of the GISP2 ice core,” Earth & Planetary Science Letters (October 2010). http://www.sciencedirect.com/science/article/pii/S0012821X10006084

Selected Speaking Engagements

- California Energy Storage Alliance, Market Development Forum (February 2019)
- Rutgers University, Rutgers Energy Institute 2018 Annual Symposium (May 2018)
- Energy Storage North America (August 2017)
- MN Energy Storage Workshop (Sept 2016 & Jan 2017);
- Arizona Corporation Commission Peak Demand Workshop, (August 2016);

- Arizona Department of Environmental Quality, Clean Power Plan Technical Working Group, (May 2016);
- Energy Storage North America (2015);
- ASU Clean Power Workshop (February 2015);
- Western Interstate Energy Board Meeting (March 2014).

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Table moves to	0
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Embedded Excel	0
Format changes	0
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